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Emission Projections for the Clean Air Act Second Section 812 Prospective Analysis

Final Report | February 2011

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APPENDICES

ACRONYMS AND ABBREVIATIONS

AEO 2005	*Annual Energy Outlook 2005*
AIM	architectural and industrial maintenance
ARB	Air Resources Board
BART	Best Available Retrofit Technology
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CBP	County Business Patterns
CENRAP	Central Regional Air Planning Association
CI	compression ignition
CNG	compressed natural gas
CO	carbon monoxide
CTGs	control technique guidelines
DOE	U.S. Department of Energy
EGAS	Economic Growth Analysis System
EGUs	electricity generating units
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
FCCUs	fluid catalytic cracking units
FCUs	fluid coking units
HAPs	hazardous air pollutants
HDDV	heavy-duty diesel vehicle
HDV	heavy-duty vehicle
I/M	inspection and maintenance
IPM	Integrated Planning Model
LADCO	Lake Michigan Air Directors Consortium
lbs	pounds

LDGV	light-duty gas vehicle
LDT	light-duty truck
LDV	light-duty vehicle
LEV	low-emission vehicle
LPG	liquefied petroleum gas
LTO	landing and takeoff
kWhrs	kilowatt-hours
MACT	maximum achievable control technology
MANE-VU	Mid-Atlantic/Northeast Visibility Union
MERR	mobile equipment repair and refinishing
MMBtu	million British thermal units
NAAQS	National Ambient Air Quality Standards
NAAs	nonattainment areas
NAICS	North American Industrial Classification System
NEI	National Emission Inventory
NEMS	National Energy Modeling System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	ammonia
NO_x	oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
OAR	Office of Air and Radiation
OB	outboard
OTAQ	Office of Transportation and Air Quality
OTC	Ozone Transport Commission
Pechan	E.H. Pechan & Associates, Inc.
PM_{10}	particulate matter of 10 microns or less
$PM_{2.5}$	particulate matter with an aerodynamic diameter of 2.5 microns or less
ppmvd	parts per million volume displacement
PWC	personal watercraft
PSD	prevention of significant deterioration

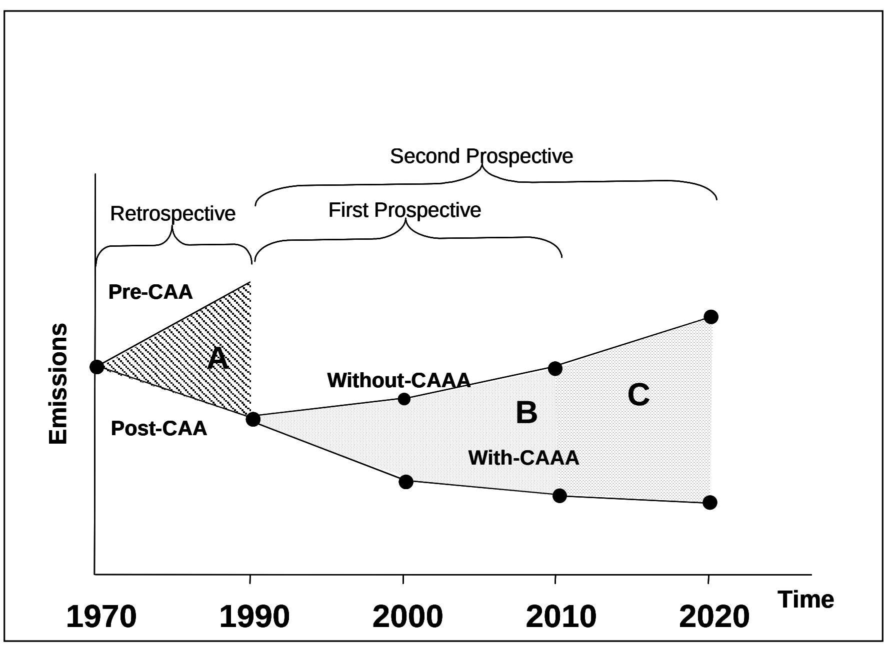
RACT	reasonably available control technology
RICE	reciprocating internal combustion engine
RPOs	regional planning organizations
RVP	Reid vapor pressure
RWC	residential wood combustion
SCC	Source Classification Code
SCR	selective catalytic reduction
S-I	spark ignition
SIC	Standard Industrial Classification
SIPs	State Implementation Plans
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
TCEQ	Texas Commission on Environmental Quality
tpy	tons per year
ULNB	ultra-low NO_x burners
USDA	U.S. Department of Agriculture
VISTAS	Visibility Improvement – State and Tribal Association of the Southeast
VMT	vehicle miles traveled
VOCs	volatile organic compounds
VRS	vapor recovery system
WRAP	Western Regional Air Partnership

CHAPTER 1 - INTRODUCTION

Section 812 of the Clean Air Act Amendments of 1990 (CAAA) required the U.S. Environmental Protection Agency (EPA) to perform periodic, comprehensive analyses of the total costs and total benefits of programs implemented pursuant to the Clean Air Act (CAA). The first analysis conducted was a retrospective analysis, addressing the original CAA and covering the period 1970 to 1990. The retrospective was completed in 1997. Section 812 also required performance of prospective cost-benefit analyses, the first of which was completed in 1999. The prospective analyses address the incremental costs and benefits of the CAAA. The first prospective covered implementation of the CAAA over the period 1990 to 2010.

EPA's Office of Air and Radiation (OAR) began work on the second prospective with the drafting of an analytical plan for the study. This analytical plan was reviewed by a statutorily-mandated outside peer review group, the Advisory Council for Clean Air Compliance Analysis (Council), and the Council provided comments, which have been incorporated into the technical analysis planning. This report describes the development of base and projection year emission estimates for the second prospective section 812 analysis. Exhibit 1-1 below outlines the relationship among the Section 812 Retrospective, the First Prospective, and the Second Prospective.

EXHIBIT 1-1. 812 SCENARIOS: CONCEPTUAL SCHEMATIC



The scope of this analysis is to estimate future emissions of criteria pollutants under two scenarios, depicted in schematic form in Exhibit 1-1 above:

1. An historical, "*with-CAAA*" scenario control case that reflects expected or likely future measures implemented since 1990 to comply with rules promulgated through September 2005[1]; and
2. A counterfactual "without CAAA" scenario baseline case that freezes the scope and stringency of emissions controls at their 1990 levels, while allowing for changes in population and economic activity and, therefore, in emissions attributable to economic and population growth.

Criteria pollutants addressed in this analysis include: volatile organic compounds (VOCs), oxides of nitrogen (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter of 10 microns or less (PM_{10}), and particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$). Estimates of current and future year ammonia (NH_3) emissions are also included in this study because of their importance in the atmospheric formation of secondary particles. Emissions of the remaining criteria pollutant, lead, are not addressed in this report because of the relatively modest impact of CAAA regulations on lead emissions.[2]

This report presents the results of EPA's analysis of the future effects of implementation of the CAAA's programs on air emissions from the following emission sectors: electricity generating units (EGUs), non-electricity generating unit point sources, nonroad engines/vehicles, on-road vehicles, and nonpoint sources. The study years for the analysis are 1990, 2000, 2010, and 2020.

The purpose of this report is to present the methods used to generate emissions projections under the two different control scenarios, and to provide emission summaries for each. Examples of programs modeled under this analysis include:

- Title I VOC and NO_x reasonably available control technology (RACT) requirements in ozone nonattainment areas (NAAs);
- Title II on-road vehicle and nonroad engine/vehicle provisions;
- Title III National Emission Standards for Hazardous Air Pollutants (NESHAPs);
- Title IV programs focused on emissions from electric generating units (EGUs).

[1] The lone exception is the Coke Ovens Residual Risk rulemaking, promulgated under Title III of the Act in March 2005. We omitted this rule because it has a very small impact on criteria pollutant emissions (less than 10 tons per year VOCs) relative to the with-CAAA scenario. The primary MACT rule for coke oven emissions, however, involves much larger reductions and therefore is included in the with-CAAA scenario.

[2] Lead emissions were effectively controlled under regulations authorized by the original Clean Air Act. As a result, analysis of lead emissions is a major focus of the section 812 retrospective study. Recent proposed revisions to the lead NAAQS could have significant effects on emissions for some localities, but those changes were first proposed on May 1, 2008, are not yet finalized, and were therefore not included in the scope of this analysis.

The results of this analysis provide the input for the air quality modeling and benefits estimation stages of the second prospective analyses. The emission inputs to the modeling are much more detailed than the summaries provided in this report. EPA plans to make a county-level version of the detailed emissions inventory files available to the public online at www.epa.gov/oar/sect812.

SUMMARY OF METHODS

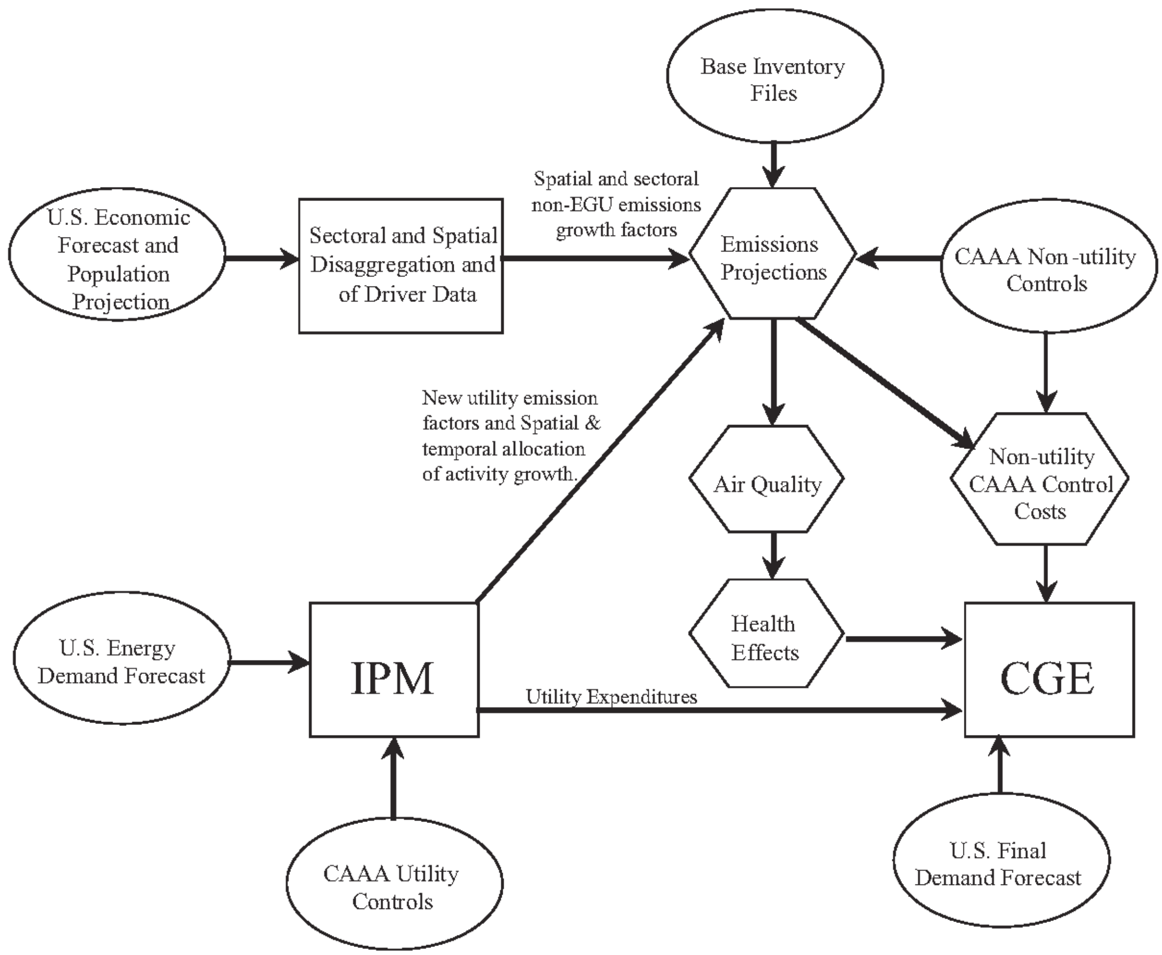
The general method we apply to estimate emissions for a major source category is as follows:

1. Select a "base" inventory for a specific year. This involves selection of an historical year inventory from which projections will be based.
2. Select activity factors to use as trend indicators for projecting emissions. The activity factors should provide the best possible means for representing future air pollutant emissions levels absent controls, at the finest feasible level of source-specific disaggregation.
3. Develop a database of scenario-specific emissions control factors, to represent emissions control efficiencies under the two scenarios of interest. The control factors are "layered on" to the projected emissions levels absent controls to estimate future emissions levels with those controls required for compliance with CAAA regulations.

This general method was applied for four of the five major source categories described in this report; this process is depicted graphically in Exhibit 1-2 below. Final demand, which represents estimates of consumer demand for goods and services from specific sectors, is a key input to CGE modeling and to some components of the emissions modeling which have their own representations of supply (e.g., the EGU sector Integrated Planning Model, IPM), but most of the emissions modeling is driven by estimates of projected economic output from the Department of Energy's *Annual Energy Outlook 2005 (AEO 2005)*, which combines demand and supply projections and modeling. Further description of *AEO 2005* is provided in Chapter 2.

Air pollutant emissions for the fifth category, EGUs, were estimated by application of the Integrated Planning Model, a model developed by ICF Consulting that estimates generation and emissions for each EGU through an optimization procedure that considers costs of electric generation, costs of pollution control, and external projections of electric demand to forecast the fuel choice, pollution control method, and generation for each unit considered in the model. The EGU modeling is a fundamentally different method for estimating emissions than the general method we use for other source categories. Our ability to use an optimization model for EGU emissions modeling reflects the enhanced data and information available for the relatively large EGU emissions sources, as well as many years of EPA and energy industry experience in modeling the national and regional markets for electricity. The EGU modeling is described in more detail in Chapter 4.

EXHIBIT 1-2. MAY 2003 ANALYTICAL PLAN - SCHEMATIC FLOW CHART



SELECTION OF BASE YEAR INVENTORY

Exhibit 1-3 summarizes the key databases that were used in this study to estimate emissions for historic years 1990 and 2000. These two years are the respective base years for preparing emission projections for the *without*- and *with-CAAA* scenarios for 2010 and 2020.

The *without-CAAA* scenario emission projections are made from a 1990 base year. For EGU and non-EGU point sources, 1990 emissions are estimated using the 1990 EPA National Emission Inventory (NEI) point source file. This file is consistent with the emission estimates used for the First Section 812 Prospective and is thought to be the most comprehensive and complete representation of point source emissions and associated activity in that year. Similarly, the 1990 EPA NEI nonpoint source file (known at the time as the area source file) – with a few notable exceptions – is used to estimate 1990 nonpoint source sector emissions. The exceptions are where 1990 emissions were re-computed using updated methods developed for the 2002 National

Emissions Inventory (NEI) for selected source categories with the largest criteria pollutant emissions and most significant methods changes. The updated methods are described in more detail in Chapter 7.

EXHIBIT 1-3. BASE YEAR EMISSION DATA SOURCES FOR THE *WITH-* AND *WITHOUT-CAAA* SCENARIOS

Sectors	*Without-CAAA* Scenario – 1990	*With-CAAA* Scenario – 2000
Non-EGU Point	1990 EPA Point Source NEI	2002 EPA Point Source NEI (Draft)
EGU	1990 EPA Point Source NEI	Estimated by the EPA Integrated Planning Model for 2001
Off-Road/Nonroad	NONROAD 2004 Model Simulation for Calendar Year 1990	NONROAD 2004 Model Simulation for Calendar Year 2000
On-Road	MOBILE6.2 Emission Factors and 1990 NEI VMT Database	MOBILE6.2 Emission Factors and 2000 NEI VMT Database. The California Air Resources Board (ARB) supplied estimates for California
Nonpoint	1990 EPA Nonpoint Source NEI with Adjustments for Priority Source Categories	2002 EPA Nonpoint Source NEI (Draft)

The 1990 onroad and nonroad vehicle/engine sector emissions were estimated independently for this project using consistent modeling approaches and activity estimates across the scenarios and years of interest. For example, MOBILE6.2 emission factors and 1990 and 2000 NEI vehicle miles traveled (VMT) databases were used to estimate onroad vehicle emissions for 1990 and 2000. Similarly, EPA's NONROAD 2004 model was used to estimate 1990 and 2000 emissions for nonroad vehicles/engines.

For calendar year 2000, *with-CAAA* scenario non-EGU point source emissions were estimated using the 2002 EPA NEI point source file (draft). We selected the year 2002 NEI to represent the year 2000 estimates for two reasons: 1) because the 2002 NEI incorporates a number of emissions methods refinements over the 1999 NEI, improving the accuracy of the base year estimate; and 2) because we believe that emissions for the year 2000 for this category are not significantly different from emissions for the year 2002. The draft NEI point source file was used because the final version was not available at the time this analysis was performed. For nonpoint sources, *with-CAAA* scenario emissions in calendar year 2000 also were estimated using the 2002 EPA NEI nonpoint source file (final), for the same reasons.

The logic for these base year inventory choices relates to the specific definitions of the scenarios themselves. The *with-CAAA* scenario tracks compliance with CAAA requirements over time; as a result, the best current basis for projecting the *with-CAAA* scenario incorporates decisions made since 1990 to comply with the act. The 2002 NEI provides the best current understanding of technologies applied to meet emissions reductions mandated under the CAAA. Over the next several decades, however, we would expect that the mix of economic activity across polluting sectors will change. In addition, we would expect that continued technological progress could improve the effectiveness and/or reduce the cost of applying these technologies. Pollution prevention and changes in production methods could also lead to reductions in air pollution. The change in the mix of economic activity is addressed directly by our choice of activity drivers for the projections, as discussed in the next section. Addressing the pace of technological progress is more difficult; in many cases, we have only limited ability to forecast technological advancements and their effect on air pollutant emissions. In other cases, we can use the pace of technological progress to date to project the pace of future improvements. To address this factor, the overall analytical plan includes an assessment of the effects of "learning by doing" on costs, in a sector-specific fashion. This is consistent with our assessment that, for most of the Federal measures assessed as part of the *with-CAAA* scenario, which require specific emissions reductions, technologies, or caps, emissions outcomes will not be affected by technological progress, but the costs of those reductions will be affected It is also consistent with the trend in emissions just prior to 1990, as documented in the First Prospective.[3] analysis. Just prior to passage of the CAAA, the steep downward emissions trends that has had been seen in the 1970's and early 1980's for many pollutants were starting to be reversed - that is, emissions were starting to move upward as economic activity continued but the stringency of standards remained largely fixed.

The *without-CAAA* scenario involves freezing the stringency of regulation at 1990 levels. Faced with the difficult task of projecting a counterfactual scenario, the Project Team considered two options:

1. base the *without-CAAA* scenario on 1990 vintage emissions rates, and adjust the rates for economic activity over time; and
2. base the *without-CAAA* scenario on recent emissions rates, and attempt to simulate the effect of removing CAAA controls in each target year.

The Project Team chose the former approach for two reasons. First, we found that removing CAAA controls from the *with-CAAA* scenario would be a very difficult task. While the subsequent chapters show that it is feasible to simulate the marginal effect of CAAA controls in projected years, a process that mirrors the type of analysis EPA routinely performs for Regulatory Impact Analyses, for the year 2000 it is not as straightforward, especially for the EGU sector because the IPM model is not designed for backcasting analyses. Second, the Project Team concluded that projecting a *without-CAAA* scenario based on a simulated year 2000 counterfactual was more problematic than using historical year results for 1990 that reflect a control scenario consistent with our definition of the *without-CAAA* scenario.

SELECTION OF ACTIVITY FACTORS FOR PROJECTIONS

Criteria pollutant emissions were projected to 2000 (for the *without-CAAA* scenario),2010, and 2020 to estimate future year emission levels. As noted above, emissions were projected under two scenarios:

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[3] The issue of the effect of technological progress is addressed in much greater detail in the report on direct costs.

Without-CAAA – applies expected increases in activity levels with no additional controls implemented beyond those that were in place when the CAAA were passed in 1990.

With-CAAA – applies expected increases in activity levels and incorporates the effects of controls mandated under the 1990 Amendments to the CAA.

Exhibit 1-4 summarizes the modeling approach used to project emissions for each of the major sectors.

EXHIBIT 1-4. MODELING APPROACH BY MAJOR SECTOR

Sector	Growth Forecast	Controls Modeling Approach
Non-EGU Point	U.S. Department of Energy (DOE) *Annual Energy Outlook 2005* forecasts	Based on control factors developed by the five Regional Planning Organizations (RPOs), and California information from the ARB
EGU	DOE *Annual Energy Outlook 2005* forecasts	Integrated Planning Model (IPM)
Nonroad	EPA NONROAD Model growth forecasts are largely based on historical trends in national engine populations by category/sub-category of engine	EPA NONROAD Model
Onroad	National VMT Forecast from *Annual Energy Outlook 2005 (AEO 2005)*	MOBILE6.2 emission factors
Nonpoint	DOE *AEO 2005* forecasts	Based on control factors developed by the five RPOs, and California information from the ARB

One of the major objectives of this study was to provide the maximum feasible internal consistency in the use of projection methods. We expect that energy demand, energy prices, and diffusion rates of technologies are closely tied to the rate of growth of future air pollutant emission and are closely linked to expectations of the future growth path of the U.S. economy. Economic growth projections enter the emissions analyses of the Second Prospective in three places:

- the electricity demand forecast included in IPM (this forecast has in the recent past been based on the reference case economic growth assumptions included in the Department of Energy's AEO 2005);
- the fuel consumption forecast for non-utility sectors that serves as the activity driver for major fuel-consuming sources (this forecast is also based on the reference case economic growth assumptions included in AEO); and
- the economic growth projections that serve as activity drivers for several other sources of air pollutants (see Chapter 2 below for more detail).

In addition, the AirControlNet model that we use to assess compliance options for meeting the new NAAQS (described in Chapter 8), and which also calculates associated emissions implications, has been re-designed to accept energy prices and labor rates as global inputs.

For this analysis, the Agency chose to use fully integrated economic growth, energy demand, and fuel price projections for "central case" economic growth scenarios. The primary advantage of this approach is that it allows the Project Team to conduct an internally consistent analysis of economic growth across all emitting sectors. In March 2005, the Project Team identified an economic/energy modeling system that could assess the impacts of alternative energy demand, fuel pricing, and technology assumptions in a fully integrated manner. The system chosen was the Department of Energy's National Energy Modeling System (NEMS). Our central case emissions estimates, described in this document, rely on the DOE Annual Energy Outlook (AEO) 2005 "reference case" scenarios. A major strength of this approach is the integrated nature of the key scenario driver data.

The Agency made this choice for two reasons: (1) the Council strongly emphasized the importance of internal analytical consistency in its review of the Analytic Blueprint; (2) consistent low-growth and high-growth projections are available in DOE's Annual Energy Outlook, facilitating analysis of the impact of alternative driver data in our future uncertainty analyses for the emissions projections. Chapter 2 provides a much more detailed explanation of the application of growth factors to three of the major source categories - the methods for EGUs and nonroad engine emissions are described within the relevant source category chapters (Chapter 4 and 5, respectively).

Another potential advantage of this approach is that the use of NEMS-based estimates may also incorporate the effects of energy efficiency enhancements that occur over time as energy using capital stock wears out and is replaced. The National Energy Modeling System is a highly detailed model of U.S. energy markets used to estimate production, prices, consumption, and imports of energy in the context of regulatory, technological, and demographic constraints. To simulate equilibrium across the U.S. energy market, NEMS adjusts different energy prices until the quantity of energy supplied equals the quantity demanded across all components of the U.S. energy market. Since supply and demand characteristics vary significantly across different regions of the U.S., NEMS includes a great deal of regional detail in seeking accuracy in its depiction of supply and demand. NEMS also focuses heavily on the state of technology in energy markets with information on costs, efficiency, and other technology-related variables included in the model. The methodologies employed by NEMS to forecast energy demand vary considerably by sector - they include econometrically based estimates, application of logistic "learning rates," and other approaches. In our analysis, these attempts to estimate gains in energy efficiency over time will be implicitly incorporated in emissions projections that are based on NEMS-derived fuel use projections. Where emissions are more closely tied to output measures, however, energy-efficiency enhancements would not necessarily be directly linked to emissions estimates. We provide more detail on the type of driver data used to generate emissions projections in Chapter 2.

APPLYING CONTROLS TO THE *WITH-CAAA* SCENARIO

Exhibit 1-5 provides a summary of the CAAA controls applied to estimate emissions for the *with-CAAA* scenario. For reference, we also indicate in the exhibit which controls were in place as of 1990 and are therefore implicitly incorporated in both scenarios. Chapters 3 through 7 provide detailed explanations of the controls applied in the *with-CAAA* scenario, as well as the results for each major sector.

This analysis is designed to reflect controls implemented by all levels of government to comply with CAAA controls. For example, Title I of the Clean Air Act requires the Agency to establish some Federal controls that apply nationwide, but this portion of the Act is focused on the establishment and compliance with National Ambient Air Quality Standards (the NAAQS). NAAQS compliance results in differing measures being implemented at the local level in response to local air quality conditions, the mix of polluting sources, and the cost of available pollution control measures. Exhibit 1-6 illustrates how the control requirements at the Federal, regional, local, and source levels are considered in order to determine the most stringent (or binding) requirement by source category for application in the core scenarios analysis. The core scenarios analysis is what is described in this report version, and it includes the measures that have been adopted by areas to meet attainment requirements for the 1-hour ozone NAAQS, and the PM_{10} NAAQS.

ASSUMPTIONS FOR BIOGENIC EMISSIONS

The emissions modeling effort documented in this report did not include developing estimates of most biogenic emissions (i.e., emissions of relevant air pollutants emitted from natural sources). In almost all cases, biogenic emissions were incorporated in the next stage of the analysis, the air quality modeling step. The lone exception is PM emissions from wildfires - our approach to estimating wildfire emissions is described in Appendix K. All other biogenic emissions estimates were derived from an EPA-supplied set of data files, which were prepared from EPA's Biogenic Emissions Inventory System, (BEIS-3) and the 2002 MM5-derived meteorological inputs (those meteorological inputs are the same as those applied in the air quality modeling). In all cases, biogenic emissions were assumed to be unaffected by the CAAA, and therefore are identical for the *with-CAAA* and *without-CAAA* scenarios. For further details, refer to the report, *Second Prospective Analysis Of Air Quality In The U.S.: Air Quality Modeling*.

ASSUMPTIONS FOR CANADIAN AND MEXICAN EMISSIONS

This document summarizes methods and results for our estimates of air pollutant emissions in the US. The next stage of the analysis, air quality modeling, also considers the impact of emissions in regions of Canada and Mexico that might influence US air quality. Canadian emissions were derived from estimates made by Environment Canada for their 2002 National Pollutant Release Inventory. Environment Canada make available both historic and projected emissions inventories - documentation and data are available at EPA's website at the following address: www.epa.gov/ttn/chief/net/canada.html. For Mexico, we used the Phase III inventory of 1999 criteria pollutant emissions, which was completed in the fall of 2006 and covers the entire country at the municipality level - see ERG and Trans Engineering (2006) for full documentation. Emissions from Canada and Mexico are the same in the *with-CAAA* and *without-CAAA* scenarios. In cases where projections are available, emissions estimates change over time.

SUMMARY OF RESULTS

Exhibit 1-7 summarizes the national emission estimates by sector for each of the scenario years evaluated in this study. Exhibit 1-8 provides emission results for all sectors combined for the same set of scenario years.[4] Exhibit 1-9 provides a graphic summary of the reductions associated with CAAA implementation for each pollutant, disaggregated by emitting sector. The ammonia emissions results, because they do not always involve reductions across the two scenarios, are not usefully informative when presented in this format, so are omitted from Exhibit 1-9. The results are discussed in detail in each of the subsequent chapters.

Exhibits 1-7 through 1-9 incorporate the results for the local controls analysis to meet attainment requirements for 8-hour ozone and $PM_{2.5}$ ambient standards, as well as the Clean Air Visibility Rule (CAVR, also known as the BART rule), that is described in detail in Chapter 8. The incremental emission reductions expected to be associated with attaining the 8-hour ozone NAAQS, the $PM_{2.5}$ NAAQS, and CAVR are measured from the core scenarios analysis *with-CAAA* scenario; to the extent that measures are identified as applying to a specific sector, the reductions are incorporated in the sector and pollutant specific results in Exhibits 1-7 and 1-9. Additional reductions needed for compliance but for which we have not identified a specific sector target are incorporated in Exhibit 1-8 and are presented as a separate category in Exhibit 1-9.

[4] A trajectory of emission reductions for each pollutant between target years can be found in Appendix I.

EXHIBIT 1-5. PROJECTION SCENARIO SUMMARY BY MAJOR SECTOR IN THE SECOND PROSPECTIVE

Sector	***Without-CAAA***	***With-CAAA****	
Non-Electricity Generating Unit Point	RACT held at 1990 levels	**NO_x**: **VOC/HAP:** **SO_x:** **NO_x/VOC:**	RACT for all NAAs (except NO_x waivers), Ozone Transport Commission (OTC) small NO_x source model rule (where adopted), Cases and settlements, NO_x measures included in ozone State Implementation Plans (SIPs) and SIP Call post-2000, Additional measures to meet PM and ozone National Ambient Air Quality Standards (NAAQS). RACT for all NAAs, VOC measures included in ozone SIPs, 2-, 4-, 7-, and 10-year maximum achievable control technology (MACT) standards, New control technique guidelines (CTGs). Cases and settlements, Additional measures to meet revised PM NAAQS. Rate-of-Progress (3 percent per year) requirements (further reductions in VOC), Early action compacts.
Electricity Generating Unit	RACT and New Source Review (NSR) held at 1990 levels. 250 ton Prevention of Significant Deterioration (PSD) and New Source Performance Standards (NSPS) held at 1990 levels.	**NO_x**: **SO_x**:	RACT and NSR for all non-waived (NO_x waiver) NAAs, SIP Call post -2000, Phase II of the OTC NO_x memorandum of understanding, Title IV Phase I and Phase II limits for all boiler types, 250 ton PSD and NSPS, Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule, Cases and settlements, Additional measures to meet PM and ozone NAAQS. Title IV emission allowance program, CAIR, Clean Air Mercury Rule, Cases and settlements, Additional measures to meet revised PM NAAQS.

Sector	*Without-CAAA*	*With-CAAA**	
Non-road Engines/ Vehicles**	Controls (engine standards) held at 1990 levels.	**NO_x**:	Federal Phase I and II compression ignition (CI) and spark-ignition (S-I) engine standards, Federal locomotive standards, Federal commercial marine vessel standards, Federal recreational marine vessel standards, NO_x measures included in ozone SIPs, Nonroad Diesel Rule.
		VOC/HAP:	Federal Phase I and II S-I engine standards, Federal recreational marine vessel standards, Federal large SI/recreational vehicle engine standards, Federal large SI/evaporative standards, VOC measures included in ozone SIPs. Federal large S-I evaporative standards,
		CO:	Federal Phase I and II S-I engine standards.
		PM:	Federal Phase I and II CI engine standards, Federal Phase I and II S-I engine standards, Federal locomotive standards, Federal commercial marine vessel standards, Nonroad Diesel Rule.
		SO_x:	Nonroad Diesel Rule, Gasoline fuel sulfur limits.

Sector	*Without-CAAA*	*With-CAAA**	
On-road Motor Vehicles***	Federal Motor Vehicle Control Program - engine standards set prior to 1990. Phase 1 Reid vapor pressure (RVP) limits. Inspection and maintenance (I/M) programs in place by 1990.	**NO_x** :	Tier 1 tailpipe standards (Title II), Tier 2 tailpipe standards, 49-State low-emission vehicle (LEV) program (Title I), I/M programs for ozone and CO NAAs (Title I), Federal reformulated gasoline for ozone NAAs (Title I), California LEV (California only) (Title I), California reformulated gasoline (California only) (Title I), NO_x measures included in ozone SIPs, heavy-duty diesel vehicle (HDDV) standards, HDDV defeat device settlements Additional measures to meet PM and ozone NAAQS.
		VOC/HAP:	Tier 1 tailpipe standards (Title II), Tier 2 tailpipe standards, 49-State LEV program (Title I), I/M programs for ozone and CO NAAs (Title I), Phase 2 RVP limits (Title II), Federal reformulated gasoline for ozone NAAs (Title I), California LEV (California only) (Title I), California reformulated gasoline (California only) (Title I), VOC measures included in ozone SIPs, HDDV standards, Enhanced evaporative test procedures, Additional measures to meet PM and ozone NAAQS.
		CO:	49-State LEV program (Title I), I/M programs for CO NAAs (Title I), Tier 2 tailpipe standards, California LEV (California only) (Title I), California reformulated gasoline (California only) (Title I), Oxygenated fuel in CO NAAs (Title I), HDDV standards.
		PM:	HDDV standards, diesel fuel sulfur content limits (Title II) (1993).
		SO_x:	Diesel fuel sulfur content limits (Title II) (1993), HDDV standards and associated diesel fuel sulfur content limits, Gasoline fuel sulfur limits, Tier 2 tailpipe standards, Additional measures to meet new PM NAAQS.

Sector	*Without-CAAA*	*With-CAAA**	
Area/Nonpoint	Controls held at 1990 levels	**NO_x**:	RACT requirements, NO_x measures included in ozone SIPs, Additional measures to meet PM and ozone NAAQS.
		VOC/HAP:	RACT requirements, New CTGs, 2-, 4-, 7-, and 10-year MACT Standards, Onboard vapor recovery (vehicle refueling), Stage II vapor recovery systems (VRS), Federal VOC rules for architectural and industrial maintenance (AIM) coatings, autobody refinishing, and consumer products, Additional measures to meet PM and ozone NAAQS.
		PM:	$PM_{2.5}$ and PM_{10} NAA controls, Co-control from VOC measures included in ozone SIPs.
		NO_x/VOC:	Rate-of-Progress (3% per year) requirements (further reductions in VOC), Model rules in OTC States, Early action compacts.

NOTES: *Also includes all *Without-CAAA* measures.

**The nonroad mobile source standards included in the *With-CAAA* scenario are based on the standards found within the NONROAD2004 emissions inventory model. Three other nonroad mobile standards, not captured by the NONROAD2004 model, are also included in the *With-CAAA* scenario: the locomotive standards, commercial marine engine standards, and the large SI/evaporative standards.

***The motor vehicle mobile source standards included in the *With-CAAA* scenario are based on the standards found within the MOBILE6.2 emissions inventory model. Note that emissions associated with the Final Rule for Cleaner Highway Motorcycles (promulgated in 2004) are not accounted for in the MOBILE6.2 model, and are not included in the *With-CAAA* scenario.

EXHIBIT 1-6. CONTROL APPLICATIONS IN THE CORE SCENARIO AND LOCAL CONTROLS FOR NAAQS COMPLIANCE ANALYSIS

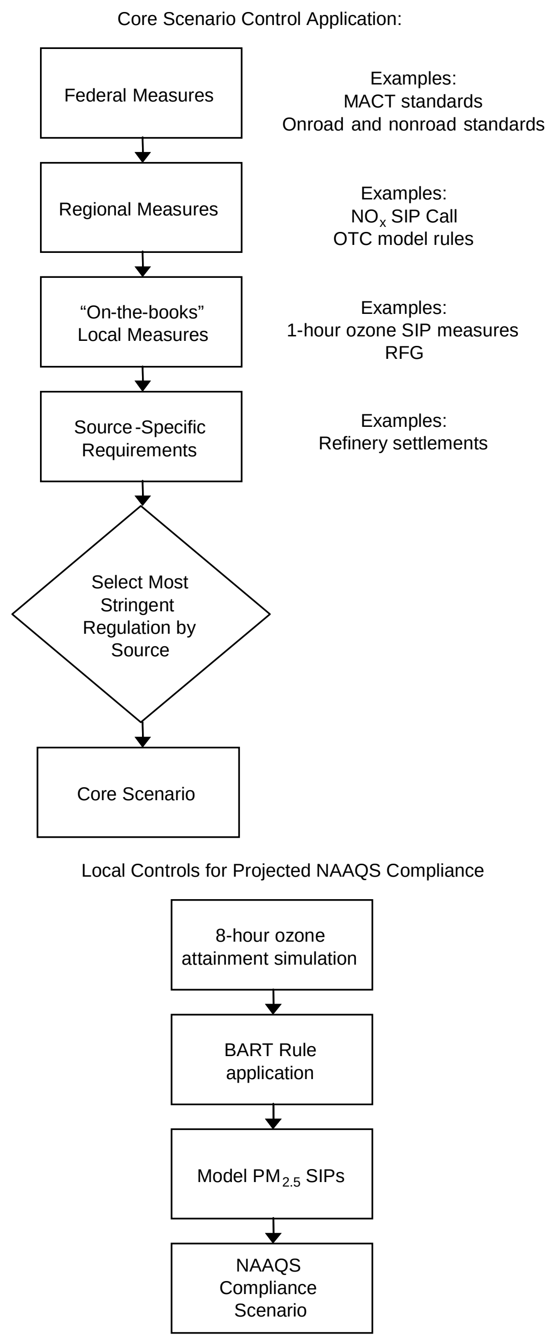


EXHIBIT 1-7. SUMMARY OF NATIONAL (48 STATE) EMISSION ESTIMATES BY SCENARIO YEAR

Pollutant	Sector	1990	2000 *without-CAAA*	2000 *with-CAAA*	2010 *without-CAAA*	2010 *with-CAAA*	2020 *without-CAAA*	2020 *with-CAAA*
VOC	EGU	34,558	40,238	40,882	43,333	42,664	48,001	46,992
	Non-EGU Point	2,609,368	3,077,597	1,402,343	3,462,797	1,434,004	3,999,199	1,645,688
	Nonpoint	11,152,804	12,268,609	8,544,345	13,425,477	8,429,089	15,702,681	9,222,786
	Nonroad	2,665,710	3,217,810	2,564,790	4,076,796	1,874,723	4,753,500	1,489,644
	On-Road Vehicle	9,327,660	5,872,983	5,245,756	5,734,012	2,592,203	6,784,539	1,645,197
NO_x	EGU	6,410,533	7,734,001	4,493,981	8,349,482	2,300,315	8,686,216	1,884,754
	Non-EGU Point	3,133,450	3,331,308	2,292,311	3,555,874	1,992,361	3,997,276	2,022,628
	Nonpoint	4,768,841	4,650,355	3,885,707	4,840,735	3,674,940	5,198,279	3,711,949
	Nonroad	2,067,745	2,190,711	2,091,459	2,664,838	1,634,025	3,162,409	996,255
	On-Road Vehicle	9,535,993	8,782,108	8,073,738	9,105,919	4,288,009	10,695,419	1,887,967
CO	EGU	303,713	496,430	503,306	602,048	617,860	750,539	771,654
	Non-EGU Point	5,667,404	6,466,855	3,112,631	6,808,250	3,290,804	7,381,679	3,677,434
	Nonpoint	16,799,105	15,634,196	14,613,968	14,707,662	14,604,856	15,088,612	15,451,445
	Nonroad	22,176,262	25,458,930	22,330,110	31,541,817	26,214,918	37,199,473	28,995,060
	On-Road Vehicle	109,566,997	79,037,081	67,130,866	80,491,386	41,976,173	95,549,545	35,741,794
SO_2	EGU	15,831,702	18,146,659	10,819,399	18,867,532	6,365,458	18,738,860	4,270,125
	Non-EGU Point	4,293,268	4,099,586	2,193,213	4,487,265	2,057,305	4,871,531	2,021,052
	Nonpoint	2,354,778	2,071,308	1,875,282	2,453,986	1,877,630	3,044,248	1,941,752
	Nonroad	163,254	178,247	177,095	225,300	16,930	270,252	2,750
	On-Road Vehicle	500,064	632,766	253,592	797,345	29,954	986,882	36,457
PM_{10}	EGU	530,663	751,696	728,719	834,655	640,502	896,790	622,419
	Non-EGU Point	1,734,810	2,013,691	597,875	2,201,812	582,635	2,491,106	681,858
	Nonpoint	22,495,048	23,118,860	19,329,848	22,816,379	18,838,781	24,255,816	19,008,256
	Nonroad	308,562	286,623	265,778	323,187	200,532	367,252	130,547
	On-Road Vehicle	384,733	247,056	220,854	229,246	150,818	268,733	134,324
$PM_{2.5}$	EGU	357,674	634,287	610,638	704,443	515,115	762,326	495,254
	Non-EGU Point	365,260	365,260	365,260	393,943	393,943	451,169	451,169
	Nonpoint	4,198,487	4,367,172	4,103,247	4,358,354	4,054,177	4,617,781	4,159,879
	Nonroad	283,960	263,798	244,620	297,466	184,593	338,036	120,262
	On-Road Vehicle	321,852	191,723	165,515	169,690	93,621	199,153	70,086
NH_3	EGU	0	3,217	3,162	1,023	822	612	559
	Non-EGU Point	243,615	236,126	153,944	237,459	173,946	255,636	201,670
	Nonpoint	3,257,139	3,621,848	3,551,567	3,828,468	3,713,161	4,130,614	3,986,783
	Nonroad	1,530	1,789	1,715	2,248	2,042	2,665	2,399
	On-Road Vehicle	154,103	272,569	272,464	336,083	334,417	397,618	395,319

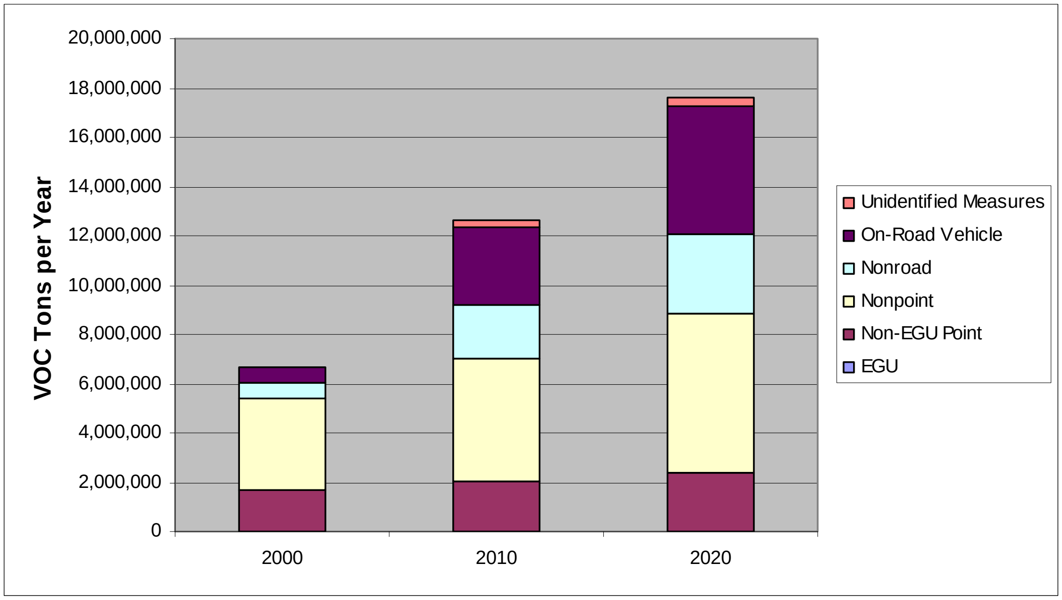
Notes:

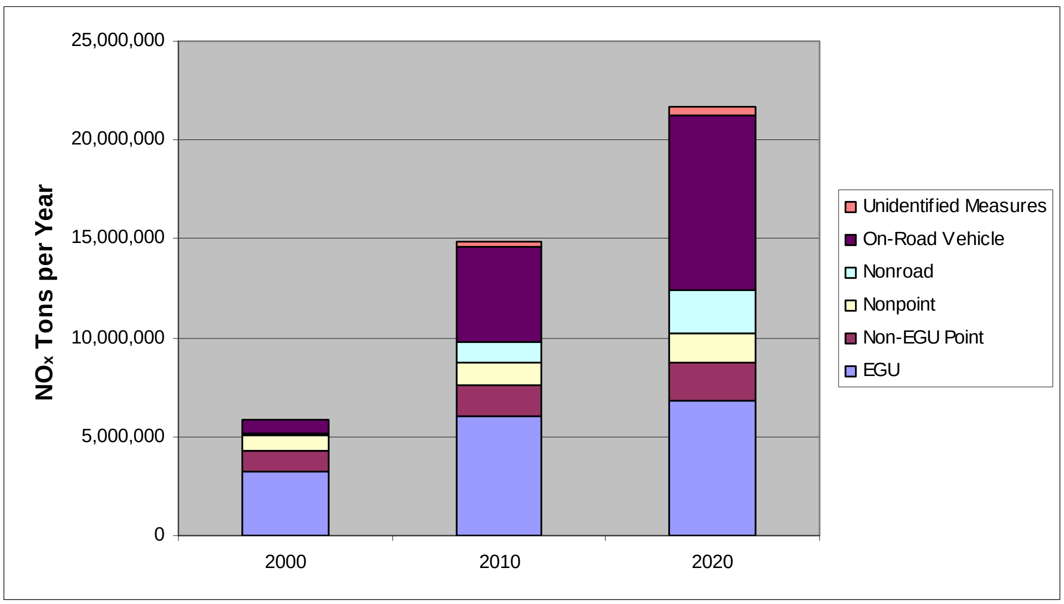
1. These estimates do not include reductions from unidentified measures, which total 255,816 tons for VOC and 249,617 tons for NO_X in 2010, 346,601 tons of VOC and 411,313 tons for NO_X in 2020.
2. These estimates include reductions in CO and PM_{10} resulting from local controls implemented for the ozone and $PM_{2.5}$ NAAQS. These reductions are not included in the discussion of local controls in Chapter 8.

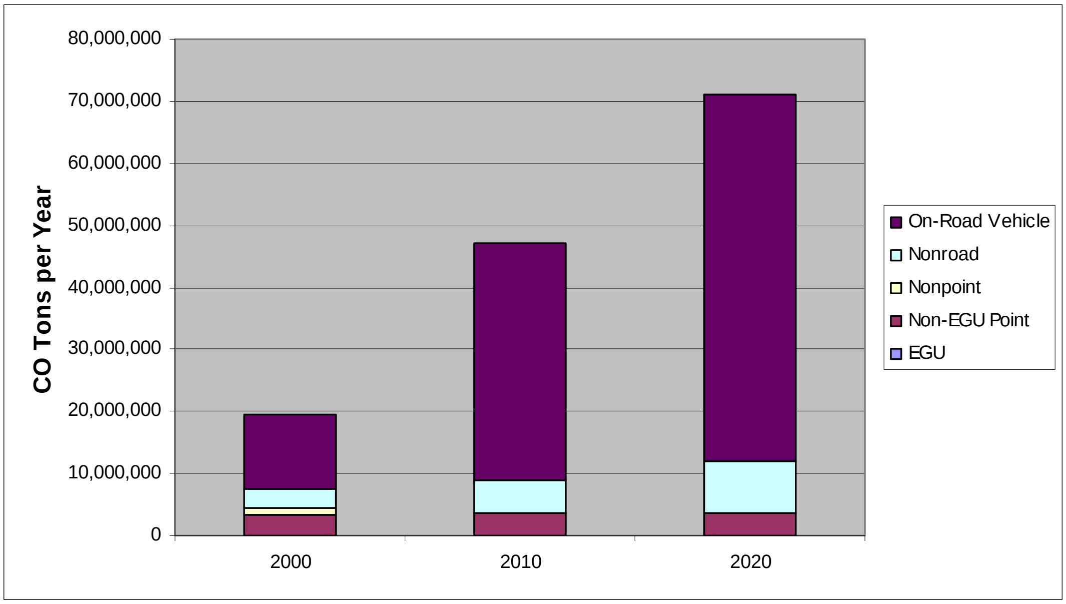
EXHIBIT 1-8. EMISSION TOTALS AND REDUCTIONS BY POLLUTANT - ALL SECTORS (THOUSAND TONS PER YEAR)

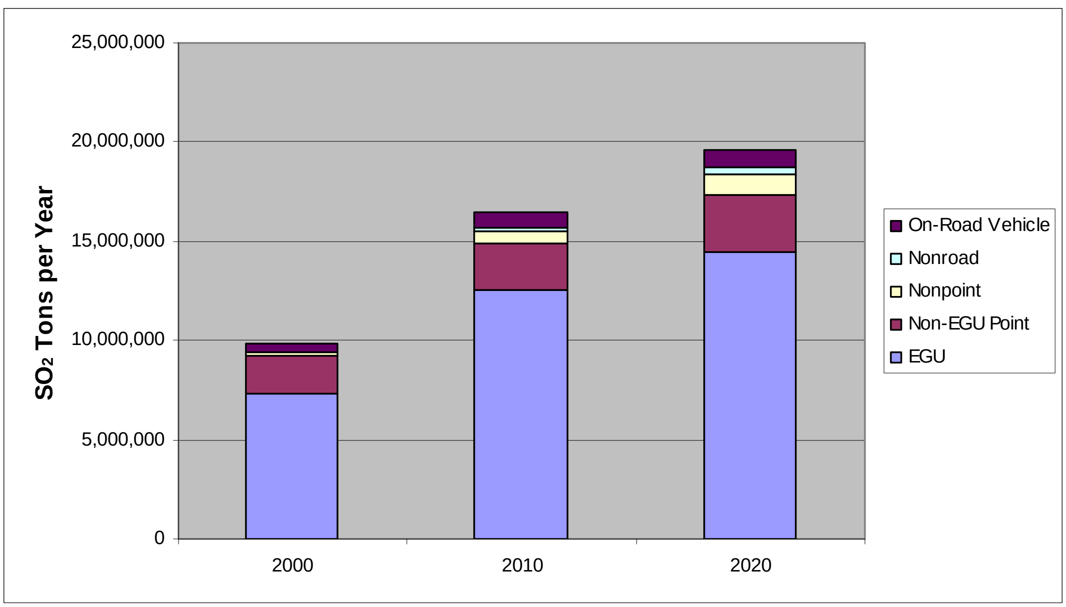
		2000			2010			2020		
Pollutant	**1990**	***without-CAAA***	***with- CAAA***	**Reduction**	***without*-CAAA**	***with-CAAA***	**Reduction**	***without-CAAA***	***with-CAAA***	**Reduction**
VOC	25,790	24,477	17,798	*6,679*	26,742	14,117	*12,626*	31,288	13,704	*17,584*
NO_x	25,917	26,688	20,837	*5,851*	28,517	13,640	*14,877*	31,740	10,092	*21,647*
CO	154,513	127,093	107,691	*19,403*	134,151	86,705	*47,447*	155,970	84,637	*71,332*
SO_2	23,143	25,129	15,319	*9,810*	26,831	10,347	*16,484*	27,912	8,272	*19,640*
PM_{10}	25,454	26,418	21,143	*5,275*	26,405	20,413	*5,992*	28,280	20,577	*7,702*
$PM_{2.5}$	5,527	5,822	5,489	*333*	5,924	5,241	*682*	6,368	5,297	*1,072*
NH_3	3,656	4,136	3,983	*153*	4,405	4,224	*181*	4,787	4,587	*200*

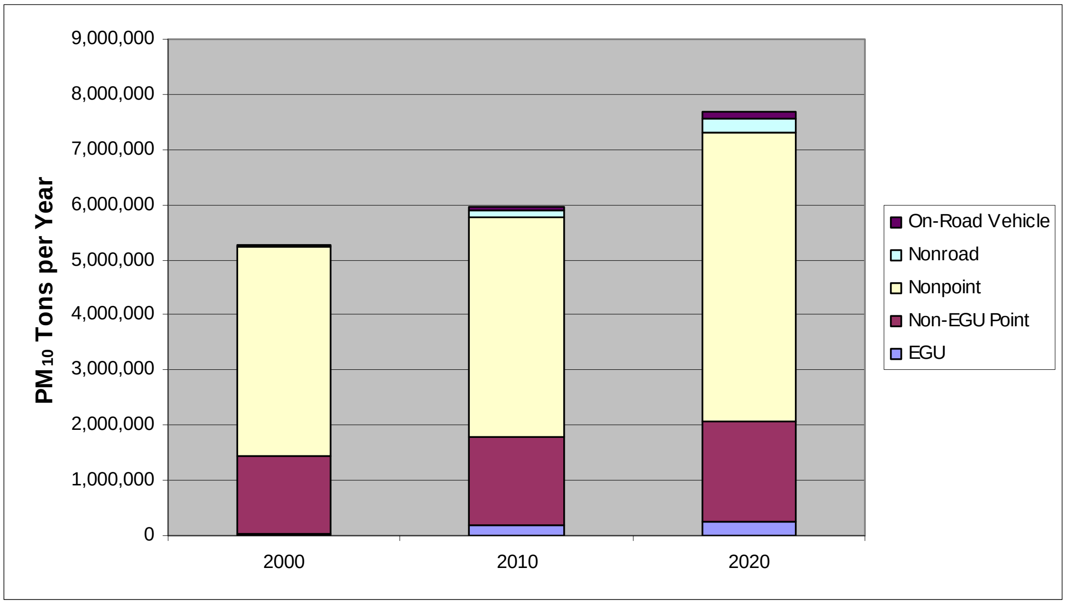
EXHIBIT 1-9. REDUCTIONS ASSOCIATED WITH CAAA COMPLIANCE BY EMITTING SECTOR

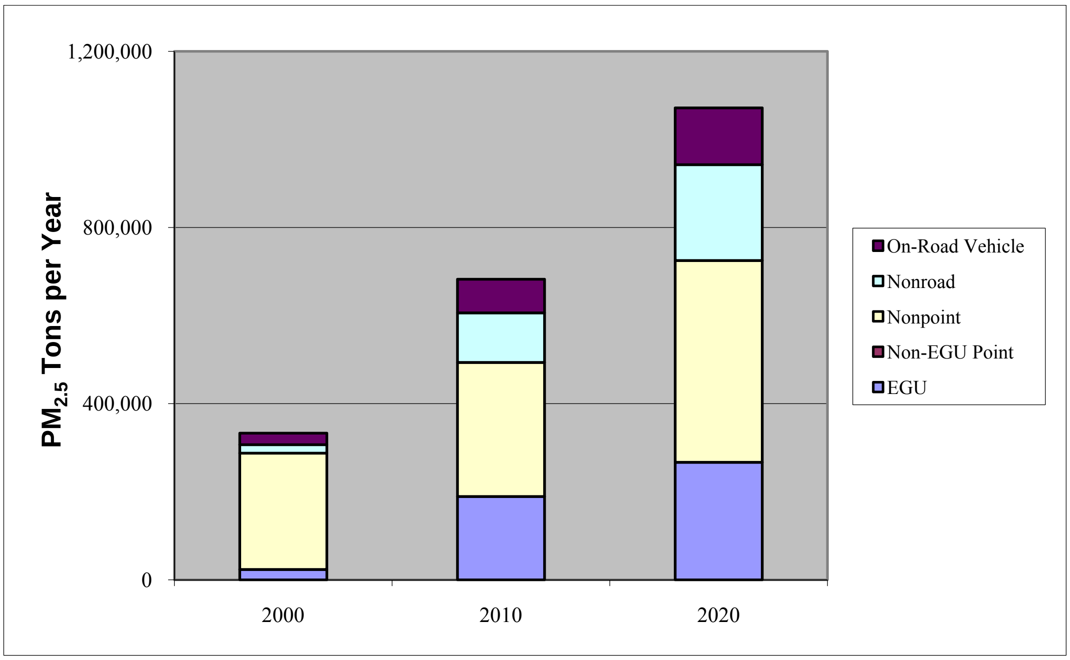


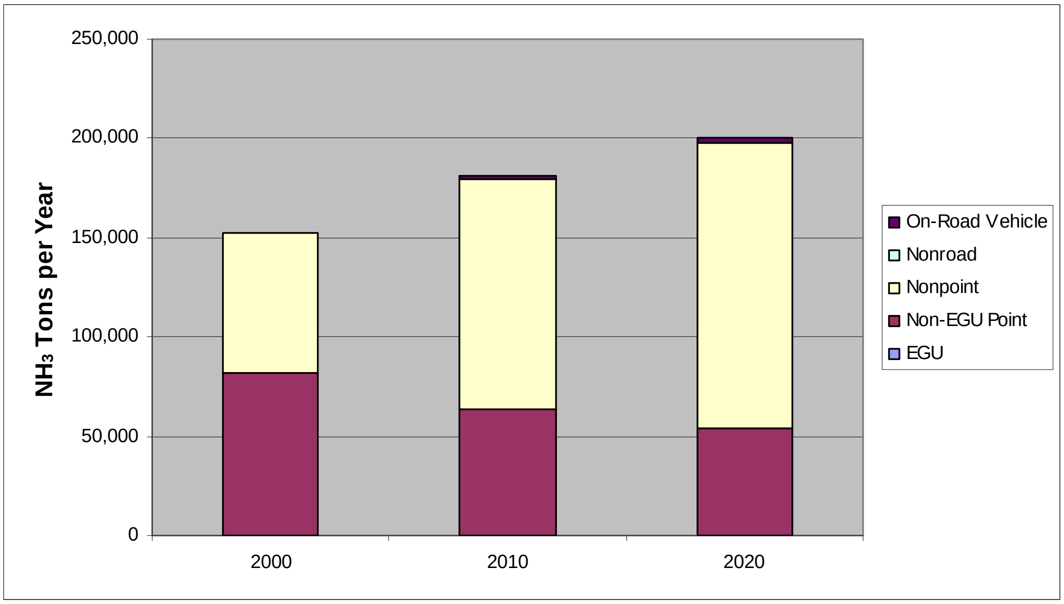



80,000,000
70,000,000
60,000,000
50,000,000
40,000,000
30,000,000
20,000,000
10,000,000
0
CO Tons per Year
2000
2010
2020
On-Road Vehicle
Nonroad
Nonpoint
Non-EGU Point
EGU


25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
SO₂ Tons per Year
2000
2010
2020
On-Road Vehicle
Nonroad
Nonpoint
Non-EGU Point
EGU


9,000,000
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
PM10 Tons per Year
2000
2010
2020
On-Road Vehicle
Nonroad
Nonpoint
Non-EGU Point
EGU


1,200,000
800,000
400,000
0
PM2.5 Tons per Year
2000
2010
2020
On-Road Vehicle
Nonroad
Nonpoint
Non-EGU Point
EGU


250,000
200,000
150,000
100,000
50,000
0
NH_3 Tons per Year
2000
2010
2020
On-Road Vehicle
Nonroad
Nonpoint
Non-EGU Point
EGU

CHAPTER 2 | EMISSION ACTIVITY INDICATORS

This chapter describes the development of emission activity factors that reflect the projected ratios of 2000, 2010, and 2020 emission activity to 1990 emission activity (for *without-CAAA* case emissions modeling) and ratios of 2010 and 2020 emission activity to 2002 emission activity (for *with-CAAA* case emissions modeling).[5] We develop emission activity levels for energy producing and consuming source categories from historical/forecast energy production/consumption data. It is not feasible, however, to develop estimates of actual emission activity levels for every non-energy related source category. Therefore, we derive historical and forecast changes in emission activity levels for these source categories from surrogate socioeconomic indicator data that are more readily available than emission activity data. The process of matching socioeconomic indicator data to source categories is described in this chapter.

As summarized in Chapter 1, for most source categories uncontrolled emissions are estimated by multiplying an emission factor by the level of emission-generating activity upon which the emission factor is based. For example, current guidance for estimating uncontrolled annual VOC emissions from gasoline service station underground storage tank breathing and emptying is to multiply the annual volume of service station gasoline throughput by an emission factor of 1.0 pounds of VOC per 1,000 gallons of gasoline (ERG, 2001). In this example, the volume of gasoline passing through service station underground storage tanks is the emissions activity. Holding aside potential process changes that may alter the relationship between the emission activity indicator and emissions (i.e., increase or decrease the emission factor), emission activity changes are proportional to changes in uncontrolled emissions.

The first section of this chapter describes the energy and socioeconomic data that were used as the starting point for estimating activity for three of the five major source categories addressed in this document: non-EGU point; mobile sources; and nonpoint sources. The discussion below also pertains to the use of such data for projecting nonroad source categories that are not incorporated into EPA's NONROAD emissions model (hereafter referred to as "miscellaneous" nonroad source categories).[6] The second section of this chapter is a discussion of alternative

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[5] As identified earlier (see Exhibit 1-3), there is no need to develop growth factors to estimate year 2000 *with CAAA* case emissions.

[6] These "miscellaneous" nonroad categories describe aircraft, marine vessel, and railroad emission processes.

data sources and methods that were used to estimate emission activity estimates for a small number of source categories for which there are not readily available activity indicators. The final section of this chapter describes how growth indicators were assigned to emission sources in the base year inventory.

Note that this chapter includes only minimal discussion of activity indicators for mobile sources. For mobile sources, the process of projecting activity involves simply taking the *AEO 2005* VMT projections for target years of interest, disaggregating spatially and to vehicle class, and using the results as input for the MOBILE 6 model. The process of disaggregation to MOBILE 6 vehicle categories and to the county level is described in Chapter 6. In addition, the process for developing appropriate activity factors for EGU and nonroad engine sources is described in Chapters 4 and 5, respectively.

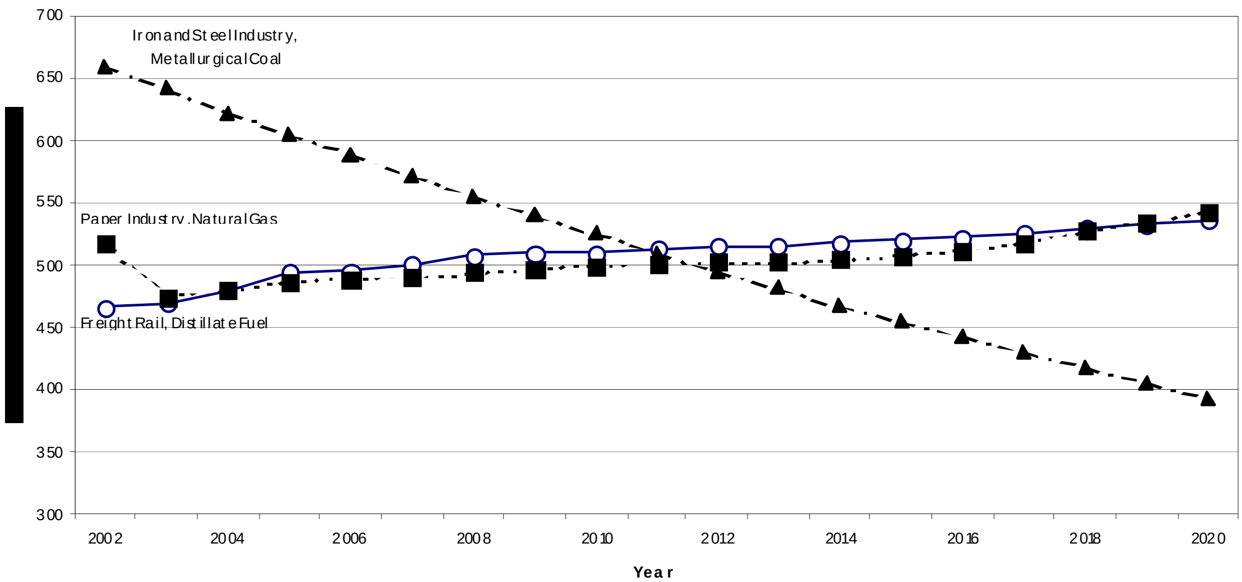
ENERGY AND SOCIOECONOMIC DATA EMISSION ACTIVITY INDICATORS

ENERGY CONSUMPTION DATA

In keeping with past EPA practice, this study relies on energy data from the U.S. Department of Energy (DOE)'s Energy Information Administration (EIA) to backcast/forecast energy consumption and energy production emission source categories. To reflect the 1990 to 2000 trend in energy consumption for source categories, the Project Team generally relied on historical time-series energy data for each State from an EIA energy consumption database (EIA, 2005b). For Crude Oil and Natural Gas Production source categories, we obtained relevant 1990 and 2000 State-level activity data from an EIA source that provides the number of operating oil well days (used for Crude Oil Production) and the number of operating gas well days (used for Natural Gas Production) (EIA, 2005c). For source categories that describe railroad and marine distillate fuel consumption emission processes, we obtained State-level 1990 and 2000 consumption estimates from an EIA distillate fuel data resource (EIA, 2005d).

Each year, the EIA produces energy projections for the United States. These projections, which forecast U.S. energy supply, demand, and prices through 2025, are published in an EIA document entitled *Annual Energy Outlook 2005 (AEO 2005)* (EIA, 2005a). For most energy sectors/fuel types, *AEO 2005* reports energy forecasts by Census division. These divisions are defined by State boundaries (e.g., Texas is included in the West South Central region). When *AEO 2005* produces Census division forecasts, these regional data were used to project changes in the emissions activity for each State in the division. For example, Stage II (Gasoline Vehicle Refueling) emission activity in Texas is projected using *AEO 2005* projections of West South Central region transportation sector motor gasoline consumption. This study relies on national energy forecasts whenever *AEO 2005* only produces national projections for the energy growth indicator of interest. Exhibit 2-1 displays forecast data for 3 of the approximately 50 energy sectors for which *AEO 2005* only produces national projections.

EXHIBIT 2-1. SAMPLE NATIONAL AEO 2005 ENERGY SECTOR FORECASTS



SOCIOECONOMIC DATA

Because population growth and the performance of the U.S. economy are two of the main determinants of energy demand, the EIA also prepares socioeconomic projections. These projections feed into energy demand models incorporated into the EIA's National Energy Modeling System (NEMS). NEMS incorporates population projections and economic output forecasts for most industry sectors by Census division. For non-energy intensive economic sectors (e.g., Wholesale Trade), EIA prepares national-level output forecasts. This study relies on *AEO2005* historical and forecast socioeconomic data as surrogates for emission activity level changes for most non-energy source categories. When *AEO 2005* reported Census division forecasts, each emission source's State identifier was used to link to the appropriate *AEO 2005* regional projections. National *AEO 2005* data were used whenever NEMS only produces national forecasts for the growth surrogate of interest. Exhibit 2-2 presents key national *AEO 2005* projections over the 2003 to 2025 forecast period.[7]

[7] As noted earlier, year 2000 emission activity data were only needed in preparing the *without-CAAA* case emission estimates from 1990 base year emissions. For 1990 and 2000, we relied on historical energy use data.

EXHIBIT 2-2. KEY NATIONAL PROJECTION RESULTS IN AEO 2005

Variable	2003 to 2025 Annual Growth Rate (%)
Population	0.8
Real Gross Domestic Product	3.1
GDP Chain-Type Price Index	2.5
Nonfarm Business Labor Productivity	2.2
Total Industrial Output	2.3
Manufacturing Output	2.6
Energy Intensive Manufacturing Output	1.5
Nonenergy Intensive Manufacturing Output	2.9
Services Sector Output	3.3
Energy Use Per Capita	0.5
Energy Use Per $ of Real Gross Domestic Product	-1.6

County-level population data are one of the key inputs to the BenMAP model used in this study to estimate the benefits of air quality changes. Population estimates at the county-level are also used as activity indicators for a small number of emissions categories. As a result, it was necessary to develop a set of population projections at the county level that is consistent with *AEO 2005* population data. The county level disaggregation step was completed using a methodology developed by Woods & Poole Economics Inc. (Woods & Poole, 2001), but updated to use *AEO 2005* regional population estimates. The first step in developing *AEO 2005* normalized county population projections was to compute factors from the population data in BenMap. These factors represent year-specific ratios of each county's BenMAP population to the BenMap population for the Census division in which the county is located. Next, the *AEO 2005* population data for each region were multiplied by the appropriate county-level factors to yield this study's county population projections.[8]

To ensure that population forecasts were available for each geographic area with stationary source/miscellaneous nonroad source category emissions in the draft 2002 NEI, we compared the NEI geographic areas to the areas in BenMAP. We identified two discrepancies between the NEI and BenMAP: BenMAP does not include Broomfield County in Colorado, and the NEI does not include Clifton Forge as an independent city in Virginia. In 2001, Clifton Forge, Virginia gave up its independent city status, and reverted back to a town. Therefore, the BenMAP Clifton Forge population estimates were added to the existing BenMAP population estimates for the county (Allegheny) in which the town is located before performing the *AEO 2005* reconciliation adjustment described above. Also in 2001, the State of Colorado

[8] Because the AEO 2005 Pacific region population estimates include Alaska and Hawaii, while BenMAP does not include these States, it was necessary to adjust the AEO projections to account for this factor. The Project team first obtained July 1, 2002 county population estimates for each State from the Bureau of the Census (BOC, 2005). Next, we compiled Alaska and Hawaii population growth factors for 2010 and 2020 from the population forecasts incorporated into the Economic Growth Analysis System (EGAS) 5.0 (Houyoux, 2004a). These growth factors were multiplied by the Census 2002 population estimates to yield population forecasts for Alaska and Hawaii that were used to adjust the AEO projections for the western regions.

created Broomfield County from areas within four counties (Adams, Boulder, Jefferson, and Weld) that contained the City of Broomfield. To develop Broomfield population estimates for each year of interest, the Project team applied factors to the *AEO 2005* adjusted BenMap population estimates for Adams, Boulder, Jefferson, and Weld counties (EPA, 2005). These factors, which reflect the proportion of the population in the City of Broomfield that was part of each of these counties in 2001, are as follows: Adams County (0.041882), Boulder County (0.073721), Jefferson County (0.002939), and Weld County (0.000055).

ALTERNATIVE EMISSION ACTIVITY INDICATORS

In some instances, energy and socioeconomic forecasts were not expected to provide satisfactory surrogates of emission activity changes. As a result, for several categories we were unable to apply *AEO 2005* data as an activity indicator. In preparing projections to support an analysis of the Clean Air Interstate Rule (CAIR), for example, EPA chose to use alternative emission activity growth surrogates for certain source categories (Houyoux, 2004). The Project Team first reviewed the data sources/approaches that were used to support the CAIR projections for application in this study. In addition, we performed new research into the availability of alternative forecast data sources for the highest criteria pollutant-emitting source categories in 2002.

Exhibit 2-3 summarizes the non-*AEO 2005* growth indicators that we applied in this study. Because of concerns about changes in emission estimation methods between the 1990 NEI and 2002 NEI, and the high level of confidence associated with the activity data for these growth indicators, the Project team replaced the 1990 base year emission estimates for the Exhibit 2-3 source categories with estimates derived from applying the estimated 1990-2002 activity level trend to the 2002 base year emissions (i.e., we backcasted 1990 emissions for these categories).[9] The following sections describe how non-*AEO 2005* emission activity indicator data were developed for the years of interest.

[9] We also replaced the NH3 and/or CO emissions in the 1990 with estimates derived from applying *AEO 2005* indicator based growth rates to 2002 NH3/CO emissions for certain categories where 1990 emissions were anomalously lower than 2002 emissions. These categories are: Open Burning of Land Clearing Debris (SCC 2610000500); Agricultural Field Burning; Field Crop is Grasses: Burning Techniques Not Important (SCC 2801500170); Agricultural Field Burning; Field Crop is Sugar Cane: Burning Techniques Not Important (SCC 2801500250); Agricultural Field Burning; Field Crop is Wheat: Headfire Burning (SCC 2801500261); Domestic Animals Waste Emissions; Cats; Total (SCC 2806010000); Domestic Animals Waste Emissions; Dogs; Total (SCC 2806015000); Wild Animals Waste Emissions; Deer; Total (SCC 2807030000); Fertilizer Application; Anhydrous Ammonia (SCC 2801700001); Fertilizer Application; Urea (SCC 2801700004); Fertilizer Application; Diammonium Phosphate (SCC 2801700013); and Prescribed Burning of Rangeland (SCC 2810020000)

AGRICULTURAL PRODUCTION-CROPS; FERTILIZER APPLICATION; NITROGEN SOLUTIONS

The Project team obtained national 1990-2002 nitrogenous solutions and urea consumption data from the Food and Agricultural Organization of the United Nations' Statistical Database (FAOSTAT, 2005a). We relied on forecasts of planted crop acreage to project the growth rate in nitrogen solution fertilizer application. We first compiled national-level 2003-2014 forecasts of total acres planted for major crops from the U.S. Department of Agriculture (USDA) (USDA, 2005). Next, we extended the acres planted projections through 2020 using linear extrapolation. Because the base year for the USDA planted acreage forecasts was 2003, We developed 2002 estimates consistent with the forecasts by applying the ratio of national 2003 acres planted to 2002 acres planted (0.995), which was calculated from historical National Agricultural Statistics Service data (NASS, 2005a). Backcast and forecast growth factors, which represented the change in emission activity level relative to 2002, were then calculated by dividing the acres planted in each historical/forecast analysis year by the acres planted in 2002.

EXHIBIT 2-3. EMISSION ACTIVITY GROWTH INDICATORS DERIVED FROM NON-AEO 2005 FORECAST DATA

Growth Indicator	Historical and Forecast Data Sources	Geographic Resolution	Forecasted Emission Activity
Agricultural Production-Crops; Fertilizer Application; Nitrogen Solutions	Historical and forecast planted acreage (NASS, 2005a and USDA, 2005)	State up thru 2002; National thereafter	Post-2003 planted acreage for major crops
Agricultural Tilling	Planted acreage (see Nitrogen Solutions entry above); assumed 2 and 6 tilling passes per year for conservation and conventional tillage, respectively; historical percentage of tilling associated with conservation tillage practices (CTIC, 2005); and assumed 50% conservation tillage in 2010 and 2020	National	Number of annual tilling passes
Animal Husbandry	Historical and projected animal counts (FAPRI, 2005; NASS, 2004 and NASS 2005b thru f; and USDA, 2005)	State up thru 2004; National thereafter except State for all years for milk cows	Number of animals (State data up through 2004; post-2004 projection reflects national animal county/production growth rates except milk cows based on State-level projections)

Growth Indicator	Historical and Forecast Data Sources	Geographic Resolution	Forecasted Emission Activity
Aircraft	Federal Aviation Administration forecasts of landing and take-off (LTO) operations (FAA, 2005)	State	Itinerant and local airport operations by type of aircraft (air carrier, general aviation, air taxi, and military)
Forest Wildfires	1990-2003 national average acres burned (EPA, 2005)	Not applicable	No change from national historical average activity (adjusted base year by average acres burned)
Prescribed Burning for Forest Management	1996-2003 national average acres burned (NIFC, 2005)	Not applicable	No change from national historical average activity (adjusted base year by average acres burned)
Residential Wood Fireplaces and Wood Stoves	*AEO 2005*, extrapolation of unit type wood consumption shares, and 2% annual turnover to EPA certified units	Region (Census division)	Residential renewable energy consumption and forecast distribution of wood consumption by unit type
Unpaved Roads	Projected unpaved road VMT developed from historical data (EPA, 2005)	Region (Census division)	Regional linear extrapolation equations

AGRICULTURAL TILLING

Agricultural tilling emissions are calculated from the number of planted acres for each crop tilled, the assumed number of passes per year used in tilling, the silt content of the surface soil, and the emission factor. To represent the change in emissions activity for this category, the Project team estimated the total annual number of tilling passes for 1990, 2000, 2002, 2004 (last year of available historical data), 2010, and 2020. The agricultural tilling emission activity estimation procedure utilized year-specific data for the number of acres of crops planted and the percentage of acres planted using conservation/conventional tillage practices.

The Project team compiled historic and future year acres planted data from the USDA. We first compiled the 1990, 2000, 2002, and 2004 national number of total planted acres from the USDA's National Agricultural Statistics Service (NASS, 2005a). Next, we obtained projections of the national planted acreage for major crops from the USDA (USDA, 2005).

Because these projections were available from 2004 through 2014, the Project team estimated planted acreage in 2020 via linear extrapolation of the USDA data. We projected total acres planted data in 2010 and 2020 by applying 2010/2004 and 2020/2004 growth factors from the USDA major crop acreage data to the actual 2004 national acres planted.

The Project team also compiled the national percentage of crops planted using conservation tillage for 1990, 2000, 2002, and 2004 from the Conservation Technology Information Center (CTIC, 2005). These data indicate a steady increase in conservation tillage – from 26.0 percent in 1990, to 36.6 percent in 2002, and 40.7

percent in 2004. Based on recent trends, we assumed that 50 percent of total acres tilled would use conservation tillage by 2010. The same 50 percent assumption was used for 2020. We then calculated the acreage associated with each form of tilling in each year by multiplying the tilling percentages in each year by the total acres planted in that year.

The following steps were used to estimate the total national number of tilling passes in each year. First, the Project team calculated the number of tilling passes associated with conservation tilling and the number with conventional tilling. Based on the crop-specific tilling pass assumptions used in the 2002 NEI, we developed assumptions that 6 passes per year and 2 passes per year are used in conventional tilling and conservation tilling, respectively. Next, we multiplied the aforementioned conventional and conservation tilling acreage estimates by the assumed number of passes associated with each tilling type. The product of this calculation yielded the total number of tilling passes in each year for each tilling type. These two values were then summed to compute the total number of passes associated with agricultural tilling in each forecast year. Backcast and forecast growth factors were computed by dividing each historical/forecast year number of passes by the 2002 year number of passes.

ANIMAL HUSBANDRY

The Project team developed inventory counts of the number of animals in 1990, 2000, 2002, 2004, 2010, and 2020 for the following animal husbandry categories: beef cows, milk cows, total non-cow cattle, total cattle, turkeys, layers, broilers, total poultry, hogs, sheep, goats, and horses. Except for horses, we developed State-level historical animal counts for each category from various USDA publications (NASS, 2004; 2005b through 2005f). Because State-level counts were not available for horses, we relied on national counts from a United Nations database (FAOSTAT, 2005b).

With the exception of milk cows, sheep, goats, and horses, the 2004 animal counts were projected to 2010 using growth rates computed from USDA national animal inventory/ production forecasts (USDA, 2005). The last year of USDA forecast data was 2014. Forecast animal counts in 2020 were developed by extrapolating the USDA's annual forecast data using linear extrapolation, and applying the resulting growth rates to the 2004 State-level animal data. For milk cows, State-level animal count projections were compiled from the Food and Agricultural Policy Research Institute (FAPRI, 2005). As with the USDA projections, it was necessary to extrapolate milk cow counts in 2020 from the annual projections data that ended in 2014. The Project team then calculated the 2010 and 2020 count of milk cows in each State by applying the State-level growth rates from the Food and Agricultural Policy Research Institute data to the 2004 count of milk cows in each State. No animal inventory or production forecasts were identified for sheep, goats, and horses. Based on a review of historical inventory data for each animal type, we applied a post-2004 no growth assumption for sheep, goats, and horses. Backcast and forecast growth factors for each animal husbandry category were computed by dividing each historical/forecast year animal count by the 2002 animal count.

AIRCRAFT

The historical/forecast State-level number of operations (arrival and departures) by type of aircraft (commercial, air taxi, and general aviation) were obtained from the Federal Aviation Administration's Terminal Area Forecasts (FAA, 2005). The Federal Aviation Administration's itinerant and local operations data were summed to develop total operations by aircraft type. Because the number of landing and take-offs (LTOs) is the emission activity for these source categories, and because an LTO is equivalent to two total operations (i.e., one arrival and one departure), we divided the number of total operations by 2 to yield the number of LTOs. Backcast/forecast year growth factors were developed for each type of aircraft by dividing the historical/forecast year LTO projections by 2002 LTO estimates. To ensure that 1990 emission values are calculated for the same SCCs and on a consistent basis with the base year and forecast year values, we replaced the 1990 base year aircraft emission estimates with estimates computed by multiplying the 2002 emissions by the ratio of 1990 LTOs to 2002 LTOs. Similarly, we computed 2000 *without-CAAA* emission estimates by multiplying 2002 emissions by the ratio of 2000 LTOs to 2002 LTOs.

FOREST WILDFIRES

In keeping with analyses performed in support of the CAIR, the Project team replaced the actual 2002 wildfire emission estimates from the draft NEI with estimates reflecting historical average wildfire activity. The Forest Wildfires source category is unique in that it is a high-emitting category for which the emissions producing activity is largely a function of meteorological conditions and unintentional activities. Because large year-to-year variations in emissions, which are common for this category, could unduly influence overall emission trends, we revised the 2002 NEI wildfire emissions by applying a factor (0.635) that represents the ratio of the national average acres burned in wildfires over the 1990-2003 period to the actual acres burned in 2002. The national 1990-2003 wildfire acres burned data were obtained from the National Interagency Fire Center (NIFC, 2005). We then used the adjusted 2002 wildfire emission estimates to represent emissions in each analysis year. This *no change* assumption was also used by EPA in analyzing the impacts of the CAIR (Houyoux, 2004b).

PRESCRIBED BURNING FOR FOREST MANAGEMENT

Similar to wildfires, prescribed burning activity levels have fluctuated widely over time. To ensure that such changes do not unduly influence overall emission trends, we adjusted the 2002 actual prescribed burning emission estimates to reflect the historical national average acres burned in prescribed fires, which was calculated from 1996-2003 data (EPA, 2005). We applied an adjustment factor of 0.730 to the 2002 NEI prescribed burning emission estimates to reflect historical average prescribed burning activity levels. We then used the adjusted 2002 prescribed fire emission estimates to represent emissions in each analysis year. This "no change" forecast assumption was also used by EPA in analyzing the impacts of the CAIR (Houyoux, 2004b).

RESIDENTIAL WOOD FIREPLACES AND WOOD STOVES

The Project team estimated emission activity levels for residential wood fireplaces and wood stoves using a combination of DOE national historical residential wood consumption estimates, *AEO 2005* Census division regional energy projections, the estimated proportion of consumption by type of unit in each analysis year, and an assumed 2 percent annual turnover to lower-emitting combustion units.

a. Energy Consumption Data

Regional residential renewable energy consumption estimates were obtained from *AEO 2005* for 2002, 2010, and 2020 (wood accounts for the vast majority of residential renewable energy consumption). Because State-level residential wood consumption estimates appeared suspect, we used DOE national 1990, 2000, and 2002 residential wood consumption data to estimate the trend in residential wood consumption over this period. We then combined the two sets of estimates to develop estimates of regional residential renewable energy consumption in each year of interest.

b. Estimates of Residential Wood Consumption Proportions by Unit Type

From the U.S. Bureau of the Census' *Census of Housing*, we obtained the 1997, 1999, 2001, and 2003 national number of homes with wood stoves and number of homes with fireplaces with inserts (BOC, 2004).[10] For fireplaces without inserts, we compiled *Census of Housing* data reflecting the number of homes that use fireplaces without inserts as the main heating source and the number of homes that use fireplaces without inserts as a supplementary heating source. We then adjusted the *Census of Housing* data to reflect the estimated number of units per home − 1.1 for fireplaces with inserts; 1.17 for fireplaces without inserts, and 1.09 for stoves and the estimated percentage of fireplaces which burn wood − 74 percent (Pechan, 2006).[11] Next, we multiplied the product of these numbers by estimated annual wood consumption per unit − 1.533 cords per unit for wood stoves and fireplaces with inserts; 0.656 cords per unit for fireplaces without inserts used as the main heating source; and 0.069 cords per unit for fireplaces without inserts used for other heating (Pechan, 2006). We then summed the main heating and other heating estimates for fireplaces without inserts to yield total wood consumption for fireplace without inserts. These calculations resulted in estimated national wood consumption for 1997, 1999, 2001, and 2003 for woodstoves, fireplaces with inserts, and fireplaces without inserts.

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[10] Pre-1997 data were not compiled because these data reflected an anomalous disconnect in the data series trend.

[11] Note that the fact that year-specific values were not identified is not a shortcoming because such values would not affect the proportion of total wood consumption associated with each type of unit, which is the goal of these steps.

Next, we computed the proportions of total residential wood consumption by each unit type for the available years. We then interpolated these proportions for the intervening years. Because pre-1997 *Census of Housing* values appeared anomalous, we chose to use the 1997 residential wood consumption proportions to represent the 1990 proportions.[12] Next we projected the wood consumption shares by residential wood combustion (RWC) unit type in 2010 and 2020 by extrapolating from the 1997-2003 values. Exhibit 2-4 presents the estimated proportions of total residential wood consumption by unit type over the 1997-2020 period.

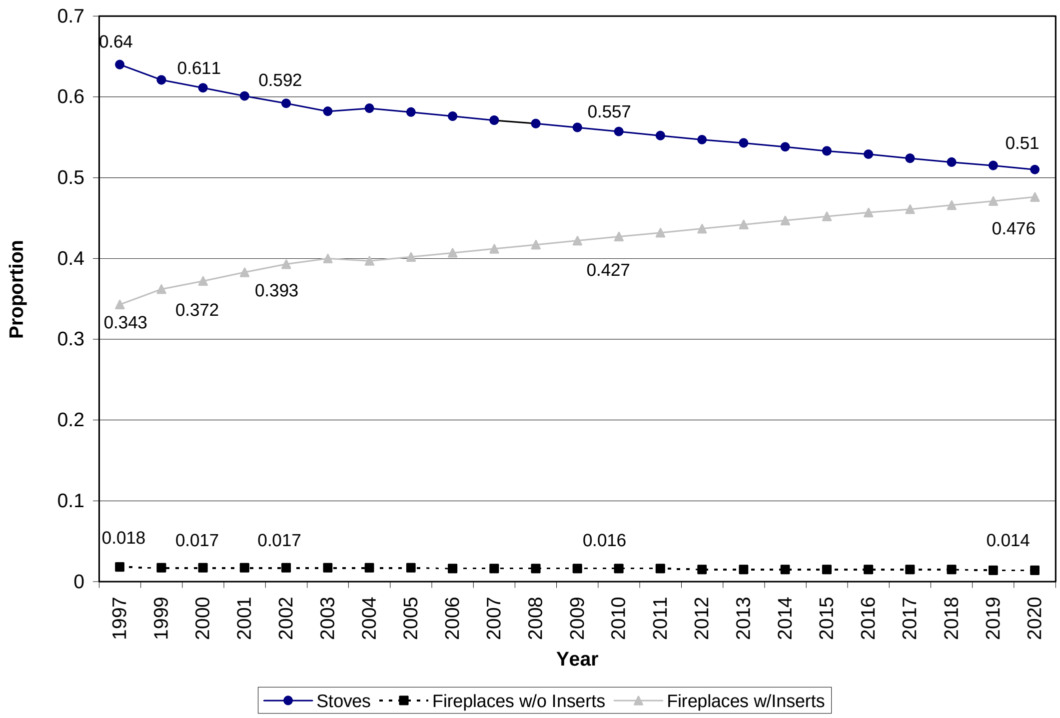
c. SCC-Level RWC Activity Consumption Forecasts

Two additional steps were used to develop source classification code (SCC)-level RWC activity forecasts. First, we estimated wood consumption by RWC unit type for the period 2002-2020 by multiplying *AEO 2005* regional 2002-2020 renewable energy consumption by 2002-2020 RWC unit type wood consumption proportions.[13] Next, for SCCs that disaggregate the broad RWC unit types reported in the *Census of Housing* data (i.e., woodstoves, fireplaces with inserts, and fireplaces without inserts), we allocated the consumption estimates to these more detailed SCCs. For the woodstoves and fireplaces with inserts categories, this step involved allocating consumption into three SCC-specific unit types representing non-EPA certified, EPA certified catalytic, and EPA certified non-catalytic units.

[12] For example, 21 to 22 percent of the total number of housing units with wood combustion equipment had fireplaces without inserts in post-1995 Census years; in 1989-1995, this percentage ranged from 32 to 33 percent. The 1997 *Census of Housing* acknowledges that pre-1997 comparability issues may exist because of significant data collection method changes that were first implemented in 1997.

[13] Note that *AEO 2005* reflects residential natural gas price forecasts (2005/2006 average of about $9.95 per thousand cubic feet in 2003 dollars) that are lower than those recently experienced (December 2005/January 2006 average of about $14.85 per thousand cubic feet in current dollars). To the extent that future year natural gas prices may be higher than assumed, *AEO 2005* may underestimate future year residential renewable energy consumption.

EXHIBIT 2-4. PROPORTION OF TOTAL RESIDENTIAL WOOD CONSUMPTION BY TYPE OF UNIT



This 2002 year allocation was accomplished by multiplying the broad unit-level consumption estimates by the proportions of total RWC attributed to each SCC as reported in the 2002 NEI: 92 percent for non-EPA certified units; 5.7 percent for EPA certified non-catalytic units; and 2.3 percent for EPA certified catalytic units (Pechan, 2006). To reflect a projected increase in EPA-certified units resulting from EPA's wood heater New Source Performance Standard (NSPS), forecast year proportions were calculated by adjusting the 2002 year proportions using an annual 2 percent RWC unit turnover rate computed from 1992-2005 data (Broderick and Houck, 2005). This adjustment accounts for non-EPA certified units being replaced by NSPS compliant EPA-certified units. Therefore, by year 2020, it is assumed that 64.4 percent of residential wood consumption in woodstoves and fireplaces with inserts will occur in non-EPA certified units, 25.4 percent in EPA certified non-catalytic units, and 10.2 percent in EPA certified catalytic units.

The Project team developed 1990 and 2000 activity level estimates as follows. We first calculated ratios representing 1990 and 2000 residential wood consumption relative to 2002 consumption (1.85 and 1.38, respectively), and then multiplied these ratios by 2002 year regional residential renewable energy consumption. Next, we applied values representing the estimated 1990 and 2000 year proportions of total residential wood consumption attributable to each of the following unit types:

woodstoves, fireplaces with inserts, and fireplaces without inserts (see Exhibit II-1).[14] Next, we allocated the general unit-level consumption estimates to individual SCCs. For 1990, this step assumed that zero residential wood consumption would occur in 1990 in EPA certified units because 1992 was the first year of certification (Broderick and Houck, 2005). For 2000, we utilized the aforementioned annual 2 percent turnover rate and the 2002 NEI wood consumption proportions to estimate the following proportions in 2000: 95.68 percent for non-EPA certified units; 3.08 percent for EPA certified non-catalytic units; and 1.24 percent for EPA certified catalytic units.

Finally, we calculated the backcast/forecast year growth factors for the RWC SCCs that appear in the 2002 base year inventory by dividing estimated historical/forecast year consumption by estimated 2002 year consumption.

UNPAVED ROADS

Unpaved road VMT is not available directly from the AEO projections. As a result, the Project team chose to compile State-level 1990-2002 unpaved road VMT data developed in support of the NEI (EPA, 2005) for application in this study.

Trends in unpaved road VMT can be upward or downward. In many areas, unpaved roads are forecast to become paved roads, reducing VMT. In other areas, unpaved roads remain unpaved and VMT grows roughly in pace with overall VMT on unpaved roads. In a few states, however, we identified anomalous VMT growth/decline between 1990 and 1995. These anomalies (e.g., 55 percent increase in Idaho unpaved road VMT between 1993 and 1994) appear to result from large year-to-year changes in estimated unpaved road mileage by traffic volume category for certain States. Anomalies such as this were identified in the following States: California, Delaware, Idaho, Nevada, Ohio, Oklahoma, Pennsylvania, Rhode Island, Tennessee, Washington, and Wyoming. For these States, we revised the 1990 to 1995 estimates by extrapolating from the 1996-2002 VMT trends. For the state of Maryland, we identified a suspect trend over the last two years of data. Therefore, we re-estimated Maryland 2001 and 2002 unpaved road VMT via linear extrapolation of the 1990-2000 VMT data.

Because of concerns over the validity of some of the State data, it was decided that the most defensible approach would be to develop *regional* level growth factors from the adjusted historical data. Therefore, we summed the unpaved VMT estimates for each State to the Census Division level and then projected 2010 and 2020 unpaved road VMT for each region using a best fit linear equation calculated from each region's 1990 to 2002 unpaved VMT data. Exhibit 2-5 presents unpaved road VMT estimates for each Census Division for 1990, 2000, 2002, 2010, and 2020.

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[14] As noted earlier, we used the 1997 proportions to represent 1990 proportions.

EXHIBIT 2-5. VMT ESTIMATES FOR UNPAVED ROADS BY CENSUS DIVISION (MILLIONS OF MILES TRAVELED)

Region	1990	2000	2002	2010	2020
East North Central	4,948	4,691	5,517	5,510	5,938
East South Central	2,646	2,329	2,161	1,687	1,099
Middle Atlantic	1,314	1,145	1,136	1,010	868
Mountain	8,550	7,347	7,149	5,989	4,425
New England	1,146	1,053	1,057	1,020	1,030
Pacific	6,033	4,403	4,366	3,331	1,931
South Atlantic	4,224	3,822	3,882	3,737	3,381
West North Central	8,361	8,991	8,899	9,398	9,906
West South Central	10,191	7,663	6,957	6,760	6,226
Totals	**47,415**	**41,445**	**41,124**	**38,442**	**34,804**

ASSIGNMENT OF GROWTH INDICATORS TO BASE YEAR EMISSION SOURCES

The following subsections describe the methods that were used to assign growth indicators to energy and non-energy related emission source categories.

ASSIGNMENTS FOR ENERGY RELATED SOURCE CATEGORIES

Because *AEO 2005* and historical EIA publications provide detailed energy production/ consumption data by sector and fuel type, energy-related source categories can be easily matched to an appropriate EIA growth indicator. The Project team assigned growth indicators to energy production/consumption emission source categories using recent Maximum Achievable Control Technology (MACT) and SCC growth indicator crosswalks developed in support of Version 5.0 of the Economic Growth Analysis System (EGAS) (Pechan, 2005a; 2005b).[15] Further detail on the crosswalk of AEO energy forecast variables is provided in Appendices F (for MACT rules) and G (for SCCs).

ASSIGNMENTS FOR NON-ENERGY RELATED SOURCE CATEGORIES

For non-energy related emission source categories, we generally utilized *AEO 2005* sector output data as surrogates for changes in emission activity.[16,17] The EGAS 5.0 sector output-based crosswalks utilize Standard Industrial Classification (SIC) code-based output projections from Regional Economic Models, Inc. (REMI) as growth indicators for non-energy related MACT and SCC codes. The EGAS 5.0 output forecasts are available for approximately 165 separate economic sectors, while the *AEO 2005* output projections are available for about 50 economic sectors (see Exhibit

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15 These crosswalks utilize *AEO 2004* data, which are reported for essentially the same sectors/fuel types as the *AEO 2005* projections data.

16 Note that unlike energy production/consumption data, historical sector output data were available from *AEO 2005*.

17 In addition to sector output, population is used as the growth indicator for some non-energy source categories.

2-6 for list of *AEO 2005* sectors). The *AEO 2005* output based growth indicators used in this study are less sector-specific than the growth indicators used in EGAS 5.0 or in the CAIR projections. However, the *AEO 2005* historical/forecast economic output data are used in this study to ensure consistency with the economic projections used in forecasting *AEO 2005* energy production/consumption. The following subsections describe how the *AEO 2005* socioeconomic data were assigned as growth indicator surrogates for non-energy related source categories.

EXHIBIT 2-6. AEO 2005 ECONOMIC SECTORS

Geography	Sector	NAICS Code(s)
Regional	MFGO1 Food Products	311
	MFGO2 Beverage and Tobacco Products	312
	MFGO3 Textile Mills & Textile Products	313,314
	MFGO4 Apparel	315
	MFGO5 Wood Products	321
	MFGO6 Furniture and Related Products	337
	MFGO7 Paper Products	322
	MFGO8 Printing	323
	MFGO9 Basic Inorganic Chemicals	32511,32519
	MFGO10 Basic Organic Chemicals	32512 – 32518
	MFGO11 Plastic and Synthetic Rubber Materials	3252
	MFGO12 Agricultural Chemicals	3253
	MFGO13 Other Chemical Products	3254 – 3259
	MFGO14 Petroleum Refineries	32411
	MFGO15 Other Petroleum and Coal Products	32412,32419
	MFGO16 Plastics and Rubber Products	326
	MFGO17 Leather and Allied Products	316
	MFGO18 Glass & Glass Products	3272
	MFGO19 Cement Manufacturing	32731
	MFGO20 Other Nonmetallic Mineral Products	327 less 3272 & 32731
	MFGO21 Iron & Steel Mills, Ferroalloy & Steel Products	3311,3312
	MFGO22 Alumina & Aluminum Products	3313
	MFGO23 Other Primary Metals	3314,3315
	MFGO24 Fabricated Metal Products	332
	MFGO25 Machinery	333
	MFGO26 Other Electronic & Electric Products	334 less 3345 & 335
	MFGO27 Transportation Equipment	336
	MFGO28 Measuring & Control Instruments	3345
	MFGO29 Miscellaneous Manufacturing	339
	MFGO30 Crop Production	111
	MFGO31 Other Agriculture, Forestry, Fishing & Hunting	112 – 115
	MFGO32 Coal Mining	2121
	MFGO33 Oil & Gas Extraction & Support Activities	211,213
	MFGO34 Other Mining & Quarrying	2122,2123
	MFGO35 Construction	23

Geography	Sector	NAICS Code(s)
	Sum of All Chemicals	325
	Sum of All Petroleum	324
	Sum of All Stone, Clay, Glass and Cement	327
	Sum of All Primary Metals	331
	Total Manufacturing Output	31 – 33
	Total Industrial Output	11,21,23,31 – 33

a. MACT Code Assignments

As part of the regulatory development process, EPA has identified the economic sectors affected by MACT standards. EPA regulatory documents generally list the North American Industrial Classification (NAICS) codes potentially affected by MACT standards. Because this information can be used to specifically relate MACT codes to NAICS codes, we used MACT codes to link to the appropriate *AEO 2005* output sector whenever a valid MACT code was reported in the base year inventory.[18] Before the transition from SIC codes to NAICS codes, EPA regulatory documents listed the SIC codes affected by MACT standards. For these regulations, we used a U.S. Bureau of the Census crosswalk that links SIC codes to NAICS codes to assign the appropriate *AEO 2005* NAICS-based growth indicator(s) to MACT codes (BOC, 2005).

b. SCC Assignments

When a valid MACT code was not available for an emission record in the inventory, we assigned the growth indicator based on the SCC. We used a combination of the EGAS 5.0 SCC-based crosswalk and the U.S. Bureau of the Census' SIC code to NAICS code crosswalk to assign *AEO 2005* NAICS-based growth indicators to SCCs. Because the EGAS 5.0 crosswalk links REMI SIC code-based economic sectors to SCCs, we used the Census' SIC code to NAICS code crosswalk to identify the *AEO 2005* sector indicator(s) to apply for a given non-energy related SCC (note that, in keeping with EGAS 5.0, population is used as the growth indicator for many such SCCs).

In some cases, the Project team did not include one or more NAICS codes that were attributable to a particular SIC code included in the EGAS 5.0 crosswalk. These exceptions result from cases where EGAS assigns a MACT code or SCC to multiple SIC codes, and where one or more of these SIC codes is associated with a NAICS sector that is expected to be much less directly related to the emission activity than the NAICS codes associated with the other SIC codes. For example, the EGAS 5.0 crosswalk assigns the All Processes/All Industries Degreasing SCC (241500000) to

[18] Because of anomalously high output-based growth rates associated with the *AEO 2005* industry sectors linked to MACT code 1614 (Halogenated Solvent Cleaning), we chose to assign growth indicators for emission records with MACT code 1614 by linking to the SCCs reported in the base year inventory (see following section for discussion of this approach).

economic output data for SIC codes 25 (Furniture and Fixtures), 33 (Primary Metal Industries), 39 (Miscellaneous Manufacturing Industries), and 75 (Automobile Repair, Services, and Parking). The AEO sectors (and NAICS codes) that match most closely to these SIC codes are: MFGO6 Furniture and Related Products (NAICS 337); MFGO23 Other Primary Metals (NAICS 3314 and 3315); MFGO29 Miscellaneous Manufacturing (NAICS 339); and NMFGO9 Other Services (NAICS 51, 54-81). Because NAICS codes 51, 54-81 are roughly equivalent to SIC codes 58, 70, 73, 75, 76, 78-80, 82-84, 86, 89, the NMFGO9 includes many more economic sectors than are included in the EGAS 5.0 crosswalk growth indicator for SCC 2415000000. Therefore, output for the NMFGO9 sector was not incorporated into the growth indicator for SCC 2415000000.

QUALITY CONTROL CHECKS AND RE-ADJUSTED EMISSIONS ACTIVITY FACTORS

A white paper prepared by EPA/OAQPS staff suggests that the emissions projection methodology that the Agency has historically used for non-EGU stationary and nonpoint sources may overestimate actual emissions for these sources.[19] As part of our quality assurance reviews of the draft Section 812 emissions inventories put before the Council Air Quality Modeling Subcommittee (AQMS), the Project Team compared emissions data from the 2002 NEI for select non-EGU stationary point source categories with estimates based on projection of the 1990 NEI estimates using EPA's current emissions projection methodology. The results allowed us to evaluate whether actual 2002 emissions from an *ex post* perspective (derived from the 2002 NEI) are comparable to estimates that would have been obtained from an *ex ante* perspective using the 1990 NEI and the current projection methods.[20] If *ex ante* estimates correspond well with *ex post* results, we can conclude that the projection method provides a reasonably unbiased estimate; if the *ex ante* estimate is higher than the *ex post* estimate, we can conclude that the projection method may overestimate actual emissions for the 1990-2002 period, as the white paper suggests.

We identified six sectors for this analysis: auto assembly plants; copper smelters; glass manufacturing; cement manufacturing (kilns); petroleum refineries; and industrial boilers. For all but one of these sectors we looked at national emissions estimates; for industrial boilers, we looked only at sources in the Midwest RPO, comprising five states: Illinois, Indiana, Michigan, Ohio, and Wisconsin. We chose a limited geographic area for the industrial boilers in part because of the ready availability of data for that region on regulatory actions during the 1990-2002 period, and in part to ensure the analysis was manageable in scope. The sectors represent a

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[19] The document, "Improving EPA Emissions Forecasting For Regulatory Impact Analyses" describes an interim approach for forecasting emissions to future years to be used in regulatory analyses, and is available at: www.epa.gov/ttn/ecas/articles.html

[20] Note that different methods and data are used in the Section 812 study than in the PM NAAQS RIA for emissions projections. The RIA is based on REMI/EGAS output, which has more detailed industry sector output data, while the 812 study is based on AEO 2005, which is more highly aggregated but based on integrated population, fuels use, and economic output modeling, as described in this chapter.

range of pollutants, geographic distribution of sources, and economic output trends - nonetheless, they are a sample of convenience and we can make no conclusive statements about the representativeness of the results for the full range of non-EGU point sources. In total, the six sector scope accounts for approximately 27, 21, 9.6, and 1.3 percent of total SO_2, NO_x, VOC and $PM_{2.5}$ emissions, respectively, in the non-EGU point source component of the 2002 NEI.

The results of our analysis did not conclusively support a particular projection method or a broad adjustment to one component of the method. Instead, the results provided insights on the types of biases the method may present and the sector-specific research needed to improve projections. For some source categories and pollutants, the projection method appears to provide an unbiased estimate. For others, the projection is higher than actual, in a few cases by a very wide margin. In still other cases, the projection is lower than actual, though the differences in those cases appear to be slight. Furthermore, within a particular source category, the results are mixed across pollutants. The implications of these results were that we re-estimated the emissions projection approach for two of the six sectors studied: copper smelters and auto assembly plants.

Copper Smelters

The results of our analysis of the copper smelter industry results highlighted a major issue with virtually any projection method - it can be very difficult to predict a major industry collapse. During the 1990-2002 period, all but three U.S. copper smelters shut down. The key industry issue in the time period was international competition in copper production. As a result, sulfur dioxide emissions dropped by almost 90 percent during this period. An additional factor contributing to the steep emissions drop was that one of the smelters still operating underwent a major modification during the mid-1990s that dramatically lowered SO_2 emissions; the impact of this upgrade was not incorporated in original emissions projections, owing to uncertainty over whether the upgrade was motivated by the CAAA regulation.

While application of a retrospective activity factor ought to have captured this substantial dropoff in copper smelter activity, in this case the Section 812 study growth factor applied is too broad to have picked up this phenomenon. The growth factor applied in the original analysis for copper smelters was for the Other Primary Metals sector, which includes all non-ferrous metals and foundries; copper smelters were clearly an exception to the otherwise increasing activity trend in the broader primary metals sector during this period.

The very large decrease in copper smelter activity in the historical period from 1990 to 2002 seems to have stabilized in recent years, with small but significant increases in North American/U.S. copper production expected in the near term. Although the Annual Energy Outlook (AEO)-based growth indicator (Other Primary Metals sector output) did a poor job of reflecting the trend in U.S. copper production between 1990 and 2002, the projected growth rates for this sector beyond 2002 are modest, and appear to be in line with short-term forecasts of copper production (1.4 to 1.5 percent annual growth). Therefore, the AEO growth indicator, though not specific to copper smelting, provides a reasonable surrogate for the expected slow growth in copper production from 2002 to 2010 and 2020. However, to improve the 1990 to 2002 emission trends estimates, the Project Team used historical data for actual copper production during this period, rather than the Other Primary Metals sector output data to reflect 1990-2002 copper smelter emissions activity.

Automobile Assembly

The results of our quality control check for auto assembly plants suggested that the projection method was not capturing several developments in this industry in the 1990 to 2002 period. Analysis of 1990-2002 VOC emission trends for automobile assembly plants showed that the AEO growth indicator (Transportation sector output) overestimated the amount of vehicle production growth over this period. Our research suggested that there were no significant regulatory changes between 1990 and 2002 affecting VOC emissions for this industry, as indicated by the fact that the 2002 alternative projection and 2002 Without CAAA emissions estimates for this sector are identical. We may have missed some State/local regulations that went into effect during the period, for example in non-attainment areas. More likely, the much lower 2002 NEI estimate appears to reflect capital turnover - there were facility closures in some locations, and the new facilities emit at lower NSPS rates.

The results suggested that a better indicator of vehicle production was needed to improve the forecasts for this source category. Therefore, for both the forecast year (2010 and 2020) and historical year (2002) analyses we changed the activity indicator for this source category to better reflect vehicle production/sales. We applied national AEO vehicle sales projections rather than regional transportation sector output projections as the emission activity indicator for this source category. In addition, we applied historical auto production data to reflect 1990-2002 emission activity trends in place of AEO Transportation Sector output data.

HIGH AND LOW ECONOMIC GROWTH SCENARIOS

To reflect the uncertainty in forecasts of economic growth, *AEO2005* includes high and low economic growth cases in addition to the reference case. The high and low growth cases are intended to show the projected effects of alternative growth assumptions on energy markets. Economic variables in the alternative cases—including GDP and its components, disposable income, interest rates, productivity, population, prices, wages, and employment—are modified, in a consistent framework, from those in the reference case. The Project Team generated an alternative set of emission forecasts using aggregated AEO 2005 high and low growth scenario information.[21] The results of these alternative scenario estimates will be used to support uncertainty analysis associated with the economic driver data.

[21] Note that, because the high and low growth scenarios were analyzed using EPA's Response Surface Model (RSM) rather than the CMAQ air quality model, the results of these alternative scenario estimates were provided as county-level

AEO's high economic growth case assumes higher projected growth rates for population (1.0 percent per year), nonfarm employment (1.6 percent per year), and productivity (2.7 percent per year) from 2003 through 2025. With higher productivity gains and employment growth, inflation and interest rates are projected to be lower than in the reference case, and economic output is projected to grow at a higher rate (3.6 percent per year) than in the reference case (3.1 percent). GDP per capita is expected to grow by 2.5 percent per year, compared with 2.2 percent in the reference case.

AEO's low economic growth case assumes lower growth rates for population (0.6 percent per year), nonfarm employment (0.8 percent per year), and productivity (1.8 percent per year), resulting in higher projections for prices and interest rates and lower projections for industrial output growth. In the low growth case, economic output is projected to increase by 2.5 percent per year from 2003 through 2025, and growth in GDP per capita is projected to average only 1.9 percent per year.

For onroad vehicles, the Project Team estimated high and low growth vehicle miles traveled (VMT) based on the corresponding high and low national forecasts from AEO 2005. The AEO 2005 VMT forecasts provide estimates for three vehicle types: light-duty vehicles less than 8,500 pounds, commercial light trucks, and freight trucks greater than 10,000 pounds. These AEO 2005 VMT estimates were used to compute high and low growth estimates by MOBILE6.2 vehicle type. The onroad vehicle emission factors for each forecast year for the high and low growth scenarios are the same as those used in the core scenario analysis (as described in Chapter 6 of this report).

For the nonroad sector, low and high growth factor adjustments for EPA NONROAD model categories were mostly tied to estimated low and high population forecasts from *AEO2005*. Nonroad equipment growth for construction, agricultural, industrial, logging, and oil field equipment was linked to non-manufacturing industrial sector growth forecasts in *AEO2005*. The Project Team estimated growth in industrial sector nonroad equipment activity using the manufacturing sector forecast for the high/low growth scenario.

Point and nonpoint source sector source category assignments to high and low growth indicators were based on national or regional indicators, based on data availability. The 2010 adjustment factors are mostly in the range of plus or minus 5 percent compared with the reference case. For 2020, the adjustment factors are mostly in the plus or minus 10 percent range.

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emission files rather than SMOKE IDA files for the following sectors: onroad vehicles, non-EGU point sources, nonpoint sources, and nonroad engines/vehicles. For the EGU sector, however, the IPM model was run in the same manner as described in Chapter 4 of this document, with the exception of the AEO driver data. For EGUs, the unit level results from the IPM run were used to estimate county-level emissions estimates.

ASSESSING THE ROLE OF DISTRIBUTED ELECTRICITY GENERATION

At an early stage of the analysis, the Council raised the issue of assessing diesel-powered distributed generation.[22] This comment had particular relevance at the time in light of the then recent electricity shortages and reliability issues in California.

The emissions and cost analysis results for the Second Prospective rely on the Department of Energy's Annual Energy Outlook (AEO) 2005, which itself implicitly reflects an estimate of the penetration of supplemental and distributed generation of electricity in the U.S. market through 2020. DOE's National Energy Modeling System (NEMS) includes a module that assesses cogeneration and distributed generation in the industrial sector, and also includes a separate module that assesses penetration of distributed generation in the commercial and residential sectors. The industrial sector cogeneration data, along with the much larger electric utility generation forecasts, are used as driver data for runs of the Integrated Planning Model (IPM). As a result, emissions from such source categories as supplemental diesel power at industrial facilities, at the higher per-unit-of-energy-produced emissions rates noted by the Council AQMS, would already be reflected in the overall EGU sector emissions summaries.

In addition, distributed generation through smaller "micropower" units is included in the non-EGU analyses. The NONROAD model includes emission estimates for the estimated 450,000 diesel-fired generators employed nation-wide. They are classified as light commercial engines, and include engines of 600 horsepower or less. The number of generators was estimated in part from engine manufacturer sales and equipment owner surveys (conducted for EPA by Power Systems Research), and verified by equipment owner surveys.

The Project Team also looked into projections of future growth in distributed generation and the potential impact on our emissions estimates. While industrial cogeneration and other industrial end user generation, even at a small scale, are already reflected in IPM, some assessments conclude that distributed end-user generation in the commercial and residential sector, which is not reflected in IPM, could be significant over the next several decades. The AEO 2005 reference case results, however, suggest relatively modest growth in this sector. EIA estimates that residential and commercial sector distributed generation is currently very small as a percentage of total electricity generation, only about 9 billion kilowatt-hours (kWhrs) out of a total generation of roughly 4 trillion kWhrs. In addition, NEMS modeling forecasts that, while this category of generation will itself grow rapidly, the total

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[22] See EPA-SAB-COUNCIL-ADV-01-004, "Review of the Draft Analytical Plan for EPA's Second Prospective Analysis - Benefits and Costs of the Clean Air Act, 1990-2020: An Advisory by the Advisory Council for Clean Air Compliance Analysis", September 24, 2001, Page 87. In Appendix G of this letter, in the context of commenting on air quality and emissions considerations involving uncertainty, the Council listed the following concern about scenario design:

"c) Supplemental diesel power: Many industrial facilities are exploring or adopting the use of supplemental diesel equipment for on-site electricity generation. These sources appear not to be regulated in the same way as traditional electrical generating units, but they can potentially produce substantial amounts of PM and nitrogen oxides."

generation is unlikely to grow to significant levels by 2020 (a projected 13 billion kWhrs out of a total 5.3 trillion generation, or less than one quarter of one percent). We would not necessarily expect that the Clean Air Act Amendments (or their absence) would have a major impact on the future adoption rate of either diesel or renewable distributed or supplemental generation. It is possible that the absence of the CAAA might reduce the air quality barriers to adoption of diesel technologies, but it is also possible that the future cost of these technologies per unit of generation might rise relative to the costs of centralized electricity sources in the absence of the Amendments.

Any forecast to 2020 of small-scale distributed generation, therefore, remains uncertain. There are many examples of published analyses that show much greater potential market penetration of small-scale, distributed renewable technologies than AEO 2005. Some analysts have concluded that the current version of NEMS is unusually pessimistic about market penetration rates. Others point to the small-scale diesel, natural gas, or renewable electric energy sources as showing promise, particularly for combined heat and power applications in new construction of commercial buildings.[23] Nevertheless, even if the penetration of these small-scale technologies were four times as great in 2020 as projected by AEO, they would make up just one percent of total generation and a much smaller portion of total emissions across all source categories. Therefore, the penetration of these technologies is unlikely to represent one of the most important sources of uncertainty in the Project Team's overall analysis of the Amendments.

[23] For a review of a wide range of analyses that consider alternative futures for distributed generation and renewables penetration see, J. Aabakken and W. Short, *Domestic Energy Scenarios,* National Renewable Energy Laboratory, Document # NREL/TP-620-32742, January 2003.

CHAPTER 3 | NON-ELECTRICITY GENERATING UNIT POINT SOURCES

OVERVIEW OF APPROACH

This chapter addresses emissions from point sources other than electric generating units. The non-EGU point source emissions category includes a diverse set of emitting sources, from multiple industries, of varying sizes, and in many cases with some variation geographically. The applicable CAAA rules for this source category are listed in Exhibit 1-5 in Chapter 1. Almost all of the rules applicable to this category are regional (e.g., the NOx SIP call) or local (i.e., in a particular city that is not attaining the National Ambient Air Quality Standard for a criteria pollution) in their implementation. Even the Federal requirements for measures such as Reasonable Available Control Technology tend to be applicable only in non-attainment areas, that is, they have a local "trigger" for implementation. As a result, much of this chapter reports on the results of our research into measures that have been applied in particular parts of the U.S. The main exception is Federal MACT standards implemented under Title III of the CAAA. For MACT standards, the focus in this chapter is not on the air toxics emissions reductions that are the main focus of those standards, but on the ancillary criteria pollution emissions reductions in the form of VOCs.

Chapter 2 describes the activity indicator portion of the emissions projection effort for non-EGU point sources; as a result, in this chapter the methods discussion focuses on how the effect of current and future control programs was incorporated in the emission projections for the *with-CAAA* scenario. The methods can be summarized as follows: the non-EGU point source emission projection approach for the *with-CAAA* scenario uses the 2002 draft NEI point source emissions file as the base year, applies the growth factors described in Chapter 2 to estimate activity changes between the base year and the 2010 and 2020 projection years, and applies control factors or emission caps to simulate the effect of air pollution control programs in each forecast year. The first section of this chapter focuses on documenting the specific control measures that are applied in the *with-CAAA* scenario, and the second section provides a summary of the emissions estimation results.

CONTROL SCENARIO METHODS

The May 2003 analytical plan proposed use of the 1999 NEI as the basis for estimating non-EGU point and nonpoint source emissions for 2010 and 2020. The draft 2002 NEI has been available since February of 2005, so it replaced the 1999 NEI as the base year emission inventory for these new projections. The 2002 NEI was the first emissions database prepared by EPA since the Consolidated Emissions Reporting Rule took effect, so the 2002 NEI represents a more complete reporting of criteria pollutant emissions and sectors by the States than the 1999 NEI. Another important attribute of the 2002 calendar year emission database is that it is the yardstick for measuring progress by the States toward reaching 8-hour ozone and $PM_{2.5}$ attainment targets. The main concern with using the 2002 draft NEI in this study was that there might be significant changes in the database made in response to quality control reviews. The Project Team decided to use the draft 2002 NEI as the basis for making 2010 and 2020 emission projections in prior drafts of this report. Since completion of the July 2006 draft report, the final NEI (Version 2.0) has been released. Changes in scheduling requirements made it possible to update key portions of the inventory to reflect these revised 2002 NEI results, including a complete re-running of all of the non-EGU point source emissions estimates documented in this chapter. Two of the major changes to be noted from the July 2006 report are new emissions rates for $PM_{2.5}$ emissions and a revised ammonia inventory. Additional information on revisions to the ammonia inventory, with particular focus on the Project Team's resolution of apparent inconsistencies for several large ammonia point sources in California, is provided in Appendix H. Additional information on the $PM_{2.5}$ emissions changes is provided in Appendix J.

One of the important components of the emission projections is identifying and quantifying the effect of Federal, State, and local air pollution control strategies on post-2002 emission rates. Because of the recent and ongoing activity of the five RPOs in developing emission projections for their own modeling domains, each of the RPOs was queried, and any available control factor files were obtained. The common projection year by the RPOs is 2018. All RPOs have either developed, or are working towards developing, 2018 emission forecasts. Some are also developing emission forecasts for 2009 or 2010 because these are expected 8-hour ozone attainment years. For the purposes of this section 812 analysis, control factors for the different projection years were reviewed, and adjusted, where necessary, to account for the timing of regulation implementation and ensure a match with this study's target years of 2010 and 2020. Exhibit 3-1 lists the RPOs, the geographic areas that they include, their projection years, and the information that was received from each to support this section 812 project.

The following sections describe the primary Federal, regional, State, and local air pollution control programs that are reflected in the 2010 and 2020 emission projections.

EXHIBIT 3-1. REGIONAL PLANNING ORGANIZATION CRITERIA POLLUTANT CONTROL FACTORS FOR REGIONS/STATES - BASE CASE 2010 AND 2020

Regional Planning Organization	Geographic Area Covered	Analysis Year(s)	Notes
1. Mid-Atlantic/ Northeast Visibility Union (MANE-VU)	Northeast and Mid-Atlantic	2018	MANE-VU provided a matrix that summarized their on-the-books rules by State and sub-state area. Their control factors were not available during this study period.
2. Visibility Improvement - State and Tribal Association of the Southeast (VISTAS)	Southeast	2009 2018	Source: MACTEC, 2005.
3. Lake Michigan Air Directors Consortium (LADCO)	Great Lakes area	2007 2009 2012 2018	Source: Pechan, 2004a.
4. Central Regional Air Planning Association (CENRAP)	Midwest	2018	Source: Pechan, 2005.
5. Western Regional Air Partnership (WRAP)	Western	2018	Control factors were not available during this study period.
5a. California		2010 2020	California projection year control factors were provided by the California Air Resources Board.

WITH-CAAA SCENARIO

Federal Programs

MACT Standards

Numerous MACT standards have been promulgated pursuant to Section 112 of Title I of the CAA, and control emissions of hazardous air pollutants (HAPs) from stationary sources of air pollution. Many HAPs are also VOCs. Many of the MACT standards are expected to produce associated VOC reductions, so the emission projections capture the expected effects of post-2002 MACT standards.

The Project Team performed the following steps to determine the MACT standards expected to have the greatest impact of VOC, NO_x, and PM emissions for the forecast year:

1. The source categories and associated SCCs for each MACT standard having a post-2002 compliance date for existing sources were identified.
2. MACT categories that do not achieve significant VOC emission reductions were eliminated.
3. VOC emission reduction estimates for the reciprocating internal combustion engine MACT category were developed based on information found in a CAIR technical support document (Alpine, 2004).

4. VOC emission reduction estimates for all other MACT categories were developed based on information found in the preamble to the final rule of each MACT Subpart as published in the *Federal Register*.[24]

Cases and Settlements

EPA completed judicial settlements with a number of companies that own U.S. petroleum refineries. For this analysis, the Project Team incorporated the expected emission reductions and costs of these consent decrees in the *with-CAAA* scenario analyses for 2010 and 2020. The focus of the 812 emission projections is on criteria air pollutants, and because the refinery settlements most affect SO_2 and NO_x, this analysis focuses on the parts of the settlements that affect SO_2 and NO_x emissions. Because of resource constraints, not all of the refineries affected by consent decrees are included in this analysis. Prioritization was established based on a ranking of the EPA-estimated criteria pollutant emission reductions by company. The companies with the largest expected emission reductions were included in this study. Exhibit 3-3 lists the companies and individual refineries that were evaluated. Exhibit 3-3 also provides information about the fluid catalytic cracking units (FCCUs) and heater/boiler emission control requirements for each refinery.

Because of the large number of refineries whose post-2000 emissions are affected by these settlements, we examined a sample of the settlements to determine where there might be common elements that could be combined into one or more model rules to most efficiently simulate the effect of the settlements. Knowing where there are differences among the settlement requirements as well as the parameters that determine the differences helped in designing an approach that would be used along with the 2002 EPA NEI and future year activity indicators to estimate 2010 and 2020 refining emissions.

[24] Exhibit 3-2 lists those MACT categories for which VOC, NO_x, and/or PM emission reduction percentages could be estimated based on emission reduction information found in the preamble to each respective final rule.

EXHIBIT 3-2. POST-2002 MACT STANDARDS AND EXPECTED VOC, NO_X, AND PM REDUCTIONS

MACT Standard - Source Category	Code of Federal Regulations Subpart	Compliance Date (existing sources)	VOC (% Reduction)	NO_x (% Reduction)	Total PM (% Reduction)
Asphalt		5/1/2006	85		
Auto and Light Duty Trucks	IIII	4/26/2007	40		
Coke Ovens: Pushing, Quenching and Battery Stacks	CCCCC	4/14/2006	43		
Fabric Printing, Coating & Dyeing	OOOO	5/29/2006	60		
Friction Products Manufacturing	QQQQQ	10/18/2005	44		
Integrated Iron and Steel	FFFFF	5/20/2006	20		20
Large Appliances	NNNN	7/23/2005	45		
Leather Finishing Operations	TTTT	2/27/2005	51		
Lime Manufacturing	AAAAA	1/5/2007			23
Manufacturing Nutritional Yeast	CCCC	5/21/2004	10		
Metal Can	KKKK	6/10/2005	70		
Metal Coil	SSSS	6/10/2005	53		
Metal Furniture	RRRR	5/23/2006	73		
Misc. Coating Manufacturing	HHHHH	12/11/2006	64		
Misc. Metal Parts and Products	MMMM	1/2/2007	48		
Misc. Organic Chemical Production and Processes	FFFF	11/10/2006	66		
Paper and Other Web	JJJJ	12/4/2005	80		
Pesticide Active Ingredient Production	MMM	12//23/2003	65		
Petroleum Refineries	UUU	4/11/2005	55		
Plastic Parts	PPPP	4/19/2007	80		
Plywood and Composite Wood Products	DDDD	9/28/2007	54		
Polymers and Resins III	OOO	1/20/2003	51		
Reciprocating Internal Combustion Engines (RICE)	ZZZZ	6/15/2007	13	17	
Rubber Tire Manufacturing	XXXX	7/11/2005	52		
Secondary Aluminum Production	RRR	3/24/2003			61
Site Remediation	GGGGG	10/8/2006	50		
Solvent Extraction for Vegetable Oil Production	GGGG	4/12/2004	25		
Stationary Combustion Turbines	YYYY	3/5/2007	90		
Taconite Iron Ore Processing	RRRRR	10/30/2006			62
Wet Formed Fiberglass Mat Production	HHHH	4/11/2005	74		
Wood Building Products	QQQQ	5/28/2006	63		

EXHIBIT 3-3. REFINERY-SPECIFIC SUMMARY OF CONSENT DECREE REQUIREMENTS

			FCCU Requirements		Heater/Boiler Requirements	
Company	Location	State	SO_2	NO_x	SO_2	NO_x
BP Amoco	Carson	CA	SO_2 catalyst additive	Low NO_x combustion promoter and NO_x adsorbing catalyst additive designed to achieve 20 parts per million volume displacement (ppmvd)	Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Whiting	IN	FCU 500: Install wet gas scrubber; FCU 600: Use SO_2 adsorbing catalyst additive and/or hydrotreatment.	FCU 600: Install SCR; FCU 500: Low NO_x combustion promoter and NO_x adsorbing catalyst additive	Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Mandan	ND	Install wet gas scrubber		Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Toledo	OH	SO_2 catalyst additive	Install SNCR system	Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Texas City	TX	FCCU3: Install wet gas scrubber; FCCU2: SO_2 catalyst additive; FCCU1: Continue hydrotreatment	FCCU 2: Install SCR to achieve 20 ppmvd or lower; FCCU 1 and FCCU 3: Low NO_x combustion promoter and NO_x adsorbing catalyst additive	Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Salt Lake City	UT	Meet an SO_2 limit of 9.8 kg/1000 kg coke burnoff		Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Yorktown	VA	Use SO_2 adsorbing catalyst additive		Elimination of oil burning and restricting H_2S in refinery fuel gas	Use qualifying controls to reduce NO_x emissions by 9632 tpy.
BP Amoco	Cherry Point	WA				
CITGO	Corpus Christi	TX	SO_2 reducing additives	FCCU1: Low NO_x combustion promoter (20 ppmvd limit); FCCU2: 23 ppmvd NO_x limit	Comply with NSPS Subparts A and J for fuel gas combustion devices. Eliminate fuel oil burning.	Use qualifying controls to reduce NO_x emissions from listed units by at least 50% of the revised baseline
CITGO Asphalt Refining Co.	Savannah	GA	No FCCU	No FCCU	Comply with NSPS Subparts A and J for fuel gas combustion devices. Eliminate fuel oil burning.	Use qualifying controls to reduce NO_x emissions from one heater or boiler
CITGO Asphalt Refining Co.	Paulsboro	NJ	No FCCU	No FCCU	Comply with NSPS Subparts A and J for fuel gas combustion devices. Eliminate fuel oil burning.	Use qualifying controls to reduce NO_x emissions from one heater or boiler

			FCCU Requirements		Heater/Boiler Requirements	
Company	**Location**	**State**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
CITGO Global Refinery	Lemont	IL	New wet gas scrubber	Low NO_x combustion promoter (20 ppmvd limit)	Comply with NSPS Subparts A and J for fuel gas combustion devices. Eliminate fuel oil burning.	Use qualifying controls to reduce NO_x emissions from listed units by at least 50% of the revised baseline
CITGO Petroleum Company	Lake Charles	LA	Unit A - SO_2 reducing additives; Unit B - New wet gas scrubber; Unit C - New wet gas scrubber	Low NO_x combustion promoter (20 ppmvd limit)	Comply with NSPS Subparts A and J for fuel gas combustion devices. Eliminate fuel oil burning.	Use qualifying controls to reduce NO_x emissions from listed units by at least 50% of the revised baseline
Conoco Philips Global Refinery	Borger	TX	Install 2 new wet gas scrubbers (to achieve 25 ppmvd)	FCCUs 29 and 40: Enhanced SCR	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Belle Chasse (Alliance)	LA	Install new wet gas scrubber (to achieve 25 ppmvd)	Scrubber-based NO_x emission reduction technology to achieve 20 ppmvd	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Linden (Bayway)	NJ	Existing wet gas scrubber (25 ppmvd or lower)	Enhanced SNCR	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy, plus install SCR on crude pipe still heater
Conoco Philips Global Refinery	Sweeny	TX	Hydrotreating the feed. SO_2 catalyst additives at FCCUs 3 and 27.	FCCU 27: Install an SCR system. By 2010, meet 20 ppmvd limit; FCCU 3: Catalyst additives and low NO_x combustion promoters	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Carson	CA			Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Wilmington	CA	SO_2 catalyst additives	NO_x catalyst additives and low NO_x combustion promoters	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Ferndale	WA	Existing wet gas scrubber (25 ppmvd or lower)	Enhanced SNCR	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Rodeo	CA			Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Santa Maria	CA			Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Trainer	PA	Install new wet gas scrubber (25 ppmvd or lower)	Enhanced SNCR	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy

			FCCU Requirements		Heater/Boiler Requirements	
Company	**Location**	**State**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
Conoco Philips Global Refinery	Roxanna (Wood River)	IL	Install new wet gas scrubber (25 ppmvd or lower)	FCCU 1: Scrubber-based NO_x emission reduction technology to achieve 20 ppmvd	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Conoco Philips Global Refinery	Hartford (Wood River)	IL	Install new wet gas scrubber (25 ppmvd or lower)	FCCU 2: Enhanced SNCR	Subject to NSPS Subparts A and J for fuel gas combustion devices	Use qualifying controls to reduce NO_x emissions from combustion units by 4951 tpy
Deer Park Refinery (Shell Oil Company)	Deer Park	TX	Install new wet gas scrubber (25 ppmvd or lower)	Install SCR designed to achieve 20 ppmvd	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Use qualifying controls to reduce NO_x emissions from combustion units
Equilon	Anacortes	WA	Install a wet gas scrubber (to achieve 25 ppmvd or lower on a 365-day rolling average basis)	Apply NO_x adsorbing catalyst additive and low NO_x CO combustion promoter	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at the companies refineries by about 6,500 tpy. Reduction via NO_x controls, unit shutdowns, and acceptance of lower permitted emission levels.
Equilon	Bakersfield	CA	No FCCU	No FCCU	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at the companies refineries by about 6,500 tpy. Reduction via NO_x controls, unit shutdowns, and acceptance of lower permitted emission levels.
Equilon	Martinez	CA	Optimize existing use of SO_2 Adsorbing Catalyst Additive. Incorporate lower SO_2 emission limits into operating permits.	Optimize existing SNCR system	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at the companies refineries by about 6,500 tpy. Reduction via NO_x controls, unit shutdowns, and acceptance of lower permitted emission levels.
Equilon	Wilmington	CA	Optimize existing use of SO_2 Adsorbing Catalyst Additive. Incorporate lower SO_2 emission limits into operating permits.	Apply NO_x adsorbing catalyst additive and low NO_x CO combustion promoter	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at the companies refineries by about 6,500 tpy. Reduction via NO_x controls, unit shutdowns, and acceptance of lower permitted emission levels.

			FCCU Requirements		Heater/Boiler Requirements	
Company	**Location**	**State**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
Marathon Ashland Refinery	Robinson	IL	Existing wet gas scrubber	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Marathon Ashland Refinery	Catlettsburg	KY	New wet gas scrubber on unit 1; catalyst additive on other unit	Apply NO_x adsorbing catalyst additive plus SNCR	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Marathon Ashland Refinery	Garyville	LA	Existing wet gas scrubber	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Marathon Ashland Refinery	Detroit	MI	SO_2 catalyst additive	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Marathon Ashland Refinery	St Paul Park	MN	New wet gas scrubber on unit 1; catalyst additive on other unit	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or

			FCCU Requirements		Heater/Boiler Requirements	
Company	**Location**	**State**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
						lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Marathon Ashland Refinery	Canton	OH	SO_2 catalyst additive	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Marathon Ashland Refinery	Texas City	TX	New wet gas scrubber	Catalyst additive plus SNCR	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers at MAP refineries by 4,000 tpy. Control methods can include: SCR or SNCR; ULNB; technologies to reach 0.040 lbs per MMBtu or lower; alternate SO_2 single burner technology to achieve 0.055 lbs per MMBtu or lower; unit shutdowns.
Montana Refining Co.	Great Falls	MT	SO_2 catalyst additive	Use NO_x reducing catalyst additive and low NO_x combustion promoters	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	No large heaters/boilers here
Motiva	Convent	LA	New wet gas scrubber	Catalyst additive	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers by about 6,500 tpy. Various control methods.
Motiva	Delaware City	DE	New wet gas scrubber	SNCR at FCU; Catalyst additives at FCCU	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers by about 6,500 tpy. Various control methods.
Motiva	Norco	LA	Existing wet gas scrubber plus lower SO_2 emission limit (25 ppmvd)	SNCR at FCCU	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers by about 6,500 tpy. Various control methods.
Motiva	Port Arthur	TX	Existing wet gas scrubber plus lower SO_2 emission limit (25 ppmvd)	Catalyst additive or meet 20 ppmvd on a 365 day rolling average basis	Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Reduce overall NO_x emissions from the controlled heaters and boilers by about 6,500 tpy. Various control methods.
Navajo	Artesia	NM	New wet gas scrubber (meet	Use NO_x reducing catalyst	Accept NSPS Subpart J applicability	Achieve 0.06 lbs/MMBtu at Boiler

			FCCU Requirements		Heater/Boiler Requirements	
Company	**Location**	**State**	**SO_2**	**NO_x**	**SO_2**	**NO_x**
Refining			25 ppmvd)	additive and low NO_x combustion promoters (NO_x rate ≤ 34.916/hr)	for heaters and boilers and reduce or eliminate fuel oil firing	B-7 and B-8
Premcor Refining (formerly Clark Refining)	Hartford	IL	Install new wet gas scrubber to meet 25 ppmvd SO_2		Accept NSPS Subpart J applicability for heaters and boilers and reduce or eliminate fuel oil firing	Install a combination of current and next generation ULNBs on identified units
Premcor Refining Group	Blue Island	IL	2001 closure	2001 closure	2001 closure	2001 closure
Sunoco Petroleum Refinery	Toledo	OH	Install new wet gas scrubber to meet 25 ppmvd SO_2	Install SCR systems or alternate technology to meet 20 ppmvd	Accept NSPS Subpart J applicability and reduce or eliminate fuel oil burning	
Sunoco Petroleum Refinery	Tulsa	OK			Refining fuel gas to meet the H_2S limits in 40 CFR 60.604(a) and (b)	
Sunoco Petroleum Refinery	Philadelphia	PA	Install new wet gas scrubber to meet 25 ppmvd SO_2	1232 FCCU: Install SCR system to meet 20 ppmvd	Accept NSPS Subpart J applicability and reduce or eliminate fuel oil burning	Use qualifying controls to reduce NO_x emissions greater than 40 MMBtu/hr by at least 2,189 tpy
Sunoco Petroleum Refinery	Marcus Hook	PA	Install new wet gas scrubber to meet 25 ppmvd SO_2	Install SCR systems or alternate technology to meet 20 ppmvd	Accept NSPS Subpart J applicability and reduce or eliminate fuel oil burning	Use qualifying controls to reduce NO_x emissions greater than 40 MMBtu/hr by at least 2,189 tpy
Valero Eagle Refinery	Texas City	TX	Use existing wet gas scrubber (achieve 25 ppmvd)	Install LoTOx system or alternative technology from each FCCU (to achieve 20 ppmvd)	Discontinue fuel oil burning. Subject to NSPS Subparts A and J for fuel gas combustion devices.	

The five major refinery sources that are affected by the judicial settlements are:

1. FCCUs/Fluid Coking Units (FCUs)
2. Process Heaters and Boilers
3. Flare Gas Recovery
4. Leak Detection and Repair
5. Benzene/Wastewater

The control requirements and, in some cases, technological options for these source types can be summarized as follows:

1. FCCU/FCU:

   a. SO_2 Option 1 – Install wet gas scrubbers

   Option 2 – Use catalyst additives

   Option 3 – Use existing wet gas scrubber

   b. NO_x Option 1 – Install selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR)Option 2 – Use catalyst additives

2. Heaters/Boilers

Control requirements apply to boilers and heaters that are 40 million British thermal units (MMBtu) per hour capacity or larger. Some emission source summaries list process heaters/boilers greater than 100 MMBtu per hour separately, but the requirements do not appear to be different from what is required for 40-100 MMBtus. In many cases, the consent decrees establish NO_x emission reduction objectives across a number of refineries that are owned by the same firm. Therefore, the companies have some discretion in deciding which individual boilers/heaters to control as well as the control techniques to apply.

   a. SO_2 Eliminate burning of solid and liquid fuels

   b. NO_x Install ultra-low NO_x burners (ULNB) or other technologies to reduce overall NO_x emissions from heaters and boilers greater than 40 MMBtu per hour

3. Flare Gas Recovery

Meet new source standards at all sulfur recovery plants and most hydrocarbon flares. Install flare gas recovery systems and take other actions to reduce emissions from process upsets. Reroute and eliminate sulfur pit emissions. Implement protocol to diagnose and prevent upsets that result in significant releases of SO_2 and other gases.

4. Leak Detection and Repair

Implement an enhanced program for identifying and repairing leaking valves and pumps, through more frequent monitoring, the use of more stringent definitions of what constitutes a leak, and regular auditing of each facility's leak detection and repair program.

5. Benzene/Wastewater

Develop an enhanced program for ensuring compliance with benzene waste management practices through comprehensive auditing, regular monitoring, and improved emission controls (e.g., secondary carbon canisters and water scrubbers).

Issues related to modeling the refinery settlement associated emission reductions are as follows:

1. Finding the FCCU/FCU records in the 2002 EPA NEI was straightforward in most situations because most refineries have one or two of these units and there are a limited number of associated SCCs. We did find one refinery where the FCCU emissions were zero, but the CO boilers had large estimated NO_x and SO_2 emissions. We applied the FCCU control requirements to the CO boiler emissions.

2. FCCU SO_2 control requirements were modeled as follows:

   a. New wet gas scrubber – a 90 percent SO_2 control efficiency was applied or the specific control efficiency listed in the consent decree, which may be slightly different from 90 percent.

   b. Catalyst additives – where required to reduce FCCU SO_2 emissions, a 70 percent control efficiency was applied. The 70 percent control efficiency was estimated from information in the literature about the expected SO_2 emission reductions of this control technique (EPA, 1989).

   c. If there was no requirement, or an existing wet gas scrubber, no additional control efficiency was applied. This may underestimate the reductions at refineries with existing wet gas scrubbers that will have to make some upgrades to their scrubbers.

3. Heater/boiler SO_2 control requirements were not applied in this analysis because it was found that there were very few fuel oil burning heaters and boilers at refineries in the NEI.

4. Heater/boiler NO_x controls for the units to which they are applied will be simulated using a 0.04 lbs per million Btu NO_x emission rate. Meeting this emission reduction requirement is expected to provide an average NO_x emission reduction of 50 percent from 2002 levels.

5. Some refineries in the 2002 NEI have provided estimates of their boiler and process heater capacities. When these estimates are provided, they are used to determine which units are subject to the boiler/heater SO_2 and NO_x control requirements (all units larger than 40 million Btu/hour with non-zero emissions are assumed to be subject to the control requirements). For refineries that do not provide the capacity values, we applied controls to all heaters and boilers with 2002 NO_x emissions above 10 tpy.

6. While the other requirements of the settlements are expected to produce additional emission reductions beyond those applied to FCCUs/FCUs and boilers and heaters, we did not incorporate these emission reductions in our emission projections. The flare gas recovery, leak detection and repair, and benzene/wastewater requirements are expected to produce less significant changes in criteria air pollutant emissions, plus these are source types for which the 2002 NEI emissions estimates are expected to be much more uncertain than they are for the combustion categories.

REGIONAL/LOCAL PROGRAMS – MANE-VU

MANE-VU was formed by the mid-Atlantic and Northeastern States, tribes, and Federal agencies to coordinate regional haze planning activities for the region. Because MANE-VU's emission projections for non-EGUs were not completed by the time this study was performed, the following methods were used to estimate control program effects on 2010 and 2020 emissions:

In October 1998, EPA issued the NO_x SIP Call, a final rule under section 110(k) of the CAA, requiring 22 States and the District of Columbia to revise their SIPs to impose additional controls on NO_x emissions. NO_x emissions for the MANE-VU States affected by the NO_x SIP Call were reduced to reflect the NO_x SIP Call requirements. MANE-VU States with NO_x SIP Call requirements include Connecticut, Delaware, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, Rhode Island, and Virginia.

These steps were applied to the four major source categories that are affected by the NO_x SIP Call as follows:

1. For boilers, all sources in the SIP Call-affected States with a boiler design capacity in the 2002 NEI greater than or equal to 250 MMBtu were deemed to be large sources.

2. For turbines, all sources in the SIP Call-affected States with a boiler design capacity in the 2002 NEI greater than or equal to 250 MMBtu were tagged as large sources.

3. For internal combustion engines, all sources with 2002 NO_x emissions greater than 1 ton per day (tpy) were tagged as large sources.

4. For cement manufacturing, all sources with 2002 NO_x emissions greater than 1 ton per day were tagged as large sources.

Once the large sources were determined, the following NO_x control percentages were applied according to the source category affected:

Industrial Boilers	60%
Gas Turbines	60%
Internal Combustion Engines	82%
Cement Manufacturing	25%

REGIONAL/LOCAL PROGRAMS - VISTAS

For the Southeast region, VISTAS provided control factor files for the requirements affecting non-EGU sources in 2009 and 2018 (MACTEC, 2005). The relevant files and a short description of the information contained in each file, and its application in this study, is provided below:

1. Atlanta SIP – NO_x control efficiencies are provided for the sources in the Atlanta, GA 1-hour ozone nonattainment area that have post-2002 emission reduction requirements.

2. NO_x SIP Phase I – For large industrial boilers and turbines, the VISTAS analysis includes States in the VISTAS region affected by the NO_x SIP Call that have developed rules. These controls were to be in effect by 2007, so the VISTAS analysis includes capped emissions for SIP Call sources at 2007 levels, which were applied to estimate 2010 and 2020 NO_x emissions at these affected facilities.

3. NO_x SIP Call Cement Kilns – This applies a 25 percent future year control efficiency to all NO_x SIP Call affected units in the VISTAS States.

4. NO_x SIP Call – Phase II – RICE Engines – This applies an 82 percent future year control efficiency to all large RICE engines in the region.

5. Refinery Cases and Settlements – Three refineries in the VISTAS region are affected by consent decrees. The refineries are (1) the Chevron refinery in Pascagoula, MS, (2) the Ergon refinery in Vicksburg, MS, and (3) the Ergon refinery in Newell, WV. Because these refineries were not included in the refinery cases and settlements analysis performed by the Project Team for this study, the VISTAS analysis was used to quantify the emission reductions for these three refineries.

REGIONAL/LOCAL PROGRAMS - MIDWEST RPO

The Midwest RPO analysis included control factor development for the following projection years: 2007, 2008, 2009, 2012, and 2018 (Pechan, 2004a). The 5-State Midwest RPO region includes Indiana, Illinois, Michigan, Ohio, and Wisconsin. The control programs affecting non-EGU point source emissions in the study region included:

- Current State/local regulations to meet 1-hour ozone requirements (e.g., regulations implementing Phase I/II NO_x SIP Call).
- MACT standards, including combustion turbine MACT and industrial boiler/process heater/RICE MACT.

In the State and sub-State areas that are affected by the NO_x SIP Call, the regulatory approaches and timing are relatively consistent across the Midwest RPO region. For example, Illinois, Indiana, Ohio, and the fine grid portion of Michigan all have industrial, commercial, and institutional boilers and gas turbines included in the trading program. Because five month ozone season NO_x allowances have been established for the large non-EGU sources in the trading program by Illinois, Indiana, Ohio, and Michigan, those allowances were used to develop plant and unit-specific

NO_x control factors to simulate the effect of this portion of the NO_x SIP Call on industrial, commercial, and institutional boilers and gas turbines.

For stationary RICE within the Midwest RPO States, the effect of the NO_x SIP Call requirements on the source category was estimated by using the EPA list of large engines by State, matching these with appropriate point IDs in the 2002 point source emissions file, and applying an 82 percent emission reduction to these specific engines. The effect of the NO_x SIP Call requirements on affected cement kilns was simulated via a 25 percent control efficiency applied to the two point source SCCs for cement kilns (30500606 and 30500706).

REGIONAL/LOCAL PROGRAMS – CENRAP

The CENRAP control factor analysis focused on Federal, State, and local rules and regulations that are expected to reduce emissions or emission rates for criteria pollutants in the CENRAP States post-2002 (Pechan, 2005c). The primary focus of the CENRAP non-EGU point source control factor analysis was on estimating the effect of 1-hour ozone nonattainment SIP rules in the areas where they apply. In addition, there are non-EGU point source NO_x control requirements in the fine grid portion of Missouri for the NO_x SIP Call.

For the 1-hour ozone nonattainment areas in Texas, non-EGU control factor development was consistent with Texas Commission on Environmental Quality (TCEQ) ozone episode modeling files. These control factors account for non-EGU control requirements in the following geographic areas: Beaumont/Port Arthur, Houston/Galveston, Dallas/Ft. Worth, and East Texas.

Beaumont/Port Arthur

The Beaumont/Port Arthur ozone nonattainment area includes Hardin, Jefferson, and Orange counties. TCEQ expects that Tier 1 reductions in NO_x emissions from these three counties will be enough for the Beaumont/Port Arthur area to attain the 1-hour ozone standard. Control factors were developed by facility and unit by the TCEQ by comparing survey results that established base year NO_x emission factors with Chapter 117 NO_x emission limits (which are by source category). The survey included all Beaumont/Port Arthur NO_x sources with 25 tpy or more of NO_x. Source-specific NO_x control factors range from 0.16 to 1.00 for affected sources.

Houston/Galveston

The Houston/Galveston ozone nonattainment area includes Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller counties. On December 6, 2000, the TCEQ adopted a program for the trading of NO_x allowances in the Houston/Galveston nonattainment area. The trading of these allowances takes place under an area-wide cap. The program requires incremental reductions beginning in 2003 and continuing through 2007, when the full reductions of the program are to be achieved. The trading program is expected to provide as much flexibility in meeting these limits as possible.

The most recent Houston/Galveston area SIP revision is based on analysis to date showing that limiting emissions of ethylene, propylene, 1,3-butadiene, and butanes in conjunction with an 80 percent reduction in NO_x is equivalent in terms of air quality benefit to that resulting from a 90 percent point source NO_x reduction requirement.

The TCEQ files for 2007 and 2010, when applied to estimate control factors for 2010 and 2020, yield a control factor of 0.45 (a 55 percent reduction). The control factor affects all non-EGU point source NO_x emissions in their nonattainment area.

There are also requirements for additional fugitive VOC emission reductions in Houston-Galveston. These include new rules to reduce emissions of highly reactive VOCs from four key industrial sources: fugitives, flares, process vents, and cooling towers. The highly reactive VOC rules are performance-based, emphasizing monitoring, record keeping, reporting, and enforcement, rather than establishing individual unit emission rates. This was decided based on a review of how such controls were applied in the Houston SIP analysis, which involved adding highly reactive VOCs to the 2000 emission inventory and removing those highly reactive VOC emissions in the future case. Ultimately, it was decided to not apply any VOC control factors to the 2002 VOC emissions in the 2010 and 2020 emission projections to account for these fugitive VOC controls. The result of this decision is that VOC emissions from this source category are probably underestimated in the section 812 analysis when compared with similar analyses performed in the Texas Air Quality Study, but that future year VOC emission estimates should be comparable.

Dallas/Fort Worth

Appendix F of the Dallas/Fort Worth ozone nonattainment demonstration (TNRCC, 1999a) identifies NO_x control factors proposed for specific industrial boilers and engines and EGUs in that area. These unit specific reductions were applied to estimate 2010 and 2020 NO_x emissions.

30 TAC 117, Subchapter 13 limits NO_x emissions from cement kilns in the Dallas/Fort Worth area. This rule establishes emission limits on the basis of lbs of NO_x per ton of clinker produced. These limits are based on the NO_x emissions averaged over each 30 consecutive day period (later changed to a 365 day period), and vary depending on the type of cement kiln. These NO_x emission limits by kiln type are as follows:

1. For each long wet kiln:
    a. In Bexar, Comal, Hays, and McLennan Counties, 6.0 lbs/ton of clinker produced
    b. In Ellis County, 4.0 lbs/ton
2. For each long dry kiln, 5.1 lbs/ton
3. For each preheater kiln, 3.8 lbs/ton
4. For each preheater-precalciner or precalciner kiln, 2.8 lbs/ton

These emission limits are expected to achieve a 30 percent reduction in cement kiln NO_x emissions.

Appendix F of the Dallas/Fort Worth ozone nonattainment demonstration (TNRCC, 1999a) identifies eleven cement kilns modeled as part of the proposed Dallas/Fort Worth NO_x emission reduction strategy. The level of NO_x controls required by the Texas Natural Resource Conservation Commission ranged by unit from 6 percent to 66 percent. These controls were applied on a unit-by-unit basis.

Control factors were developed by facility and unit by the TCEQ using the same emission factor survey and comparison with NO_x emission limit technique that was described above for Beaumont-Port Arthur. The survey included all Dallas/Fort Worth NO_x sources that reported 2 tons per year or more of NO_x. Source-specific control factors range from 0.13 to 1.00 for affected sources.

Agreed order control factors from the TCEQ were applied to simulate the effects of such orders on two facilities. A control factor of zero is applied to the Eastman plant (482030019), simulating the shutdown of this facility. NO_x control factors are applied to three boilers at the Alcoa (483310001) aluminum production facility. The Alcoa emission changes are in response to a consent decree.

Another TCEQ control factor file contains information about the future year criteria pollutant emissions for the cement kilns in Ellis County. These emission estimates were used to estimate appropriate growth and control factors for the 2010 and 2020 emission forecasts for this area/source category.

Missouri

The fine grid counties in eastern Missouri are affected by EPA NO_x SIP Call requirements. The State of Missouri supplied information about unit-specific NO_x emission reductions for affected facilities. For non-EGUs, this included an 8 ton per ozone season NO_x emission limit applied to Anheuser Busch-Unit 6, a 9 ton per ozone season limit applied to Trigen-Unit 5, and a 36 ton per ozone season limit applied to Trigen-Unit 6.

Kansas

Rule 28-19-717 requires control of VOC emissions from commercial bakery ovens in Johnson and Wyandotte counties. This rule applies to bakery ovens with a potential to emit VOCs equal to or greater than 100 tpy. Each commercial bakery oven (at the unit-level) subject to this regulation shall install and operate VOC emissions control devices for each bakery oven to achieve at least an 80 percent total removal efficiency on the combined VOC emissions of all baking ovens, calculated as the capture efficiency times the control device efficiency. Each bakery oven unit in these two counties with more than 100 tpy of VOC emissions in 2002 had an 80 percent VOC control efficiency applied in the 2010 and 2020 projections.

Louisiana

Point sources in the Baton Rouge nonattainment area and the nearby region of influence are affected by Chapter 22 NO_x control provisions. The provisions of this chapter apply to any affected facility in the Baton Rouge nonattainment area (the entire parishes of Ascension, East Baton Rouge, Iberville, Livingston, and West Baton Rouge) and the Region of Influence (affected facilities in the attainment parishes of East Feliciana, Pointe Coupee, St. Helena, and West Feliciana). The provisions of this chapter apply during the ozone season (May 1 to September 30) of each year. Based on the stated compliance deadline of May 1, 2005, we modeled this rule as fully in effect by 2005.

The effects of this NO_x regulation were included in the analysis by applying a 34 percent NO_x emission reduction to the 2002 non-EGU point source emissions in the greater Baton Rouge area. This control factor application is consistent with what was included in the most recent Houston-Galveston area modeling domain assessments by the TCEQ.

REGIONAL/LOCAL PROGRAMS – WRAP

The WRAP Stationary Sources Forum is currently revising its 2018 emission projections from a 2002 base year. The summary information provided by the WRAP for its ongoing project indicated that there are very few post-2002 stationary source control requirements in the region outside the State of California. The information that the WRAP study had included on refinery cases and settlements was limited, so the information on refinery cases and settlements that was gathered for this section 812 project was used to characterize the emission changes from those initiatives.

In order to estimate the 2010 and 2020 emission benefits of air pollution emission regulations in California, a request was made to the California ARB to provide control factors that the ARB uses in its own emission projections. ARB staff provided a control factor file that was used in the Central California Ozone Study modeling effort. The Central California Ozone Study projections were based on the 1999 inventory, so the control factors are normalized to 1999. Because 2002 control factors were provided, the 2010 and 2020 control factors were normalized to a 2002 base year by Pechan. This normalization divides the 2010 and 2020 control factors by the associated 2002 control factors for each pollutant and source category. The California file includes control factors by district, air basin, and county, with source categories designated by California's Emission Inventory Codes. The California file has both rule-specific and composite (with all rules applied) control factors. The composite control factors were used in this analysis.

WITHOUT-CAAA SCENARIO

The base year for the evaluation of the *without-CAAA* scenario is the 1990 EPA NEI. For point sources, this database was used along with the activity growth indicators described in Chapter II to estimate *without-CAAA* emissions in 2000, 2010, and 2020.

Because the 1990 NEI was developed before information was available to State, local, and tribal emission inventory preparers about how to estimate PM-filterable and PM-condensable fractions, it was necessary to augment the 1990 NEI point source file to have it include estimates of all of the PM components.

The methods that were used to perform this PM emissions augmentation are consistent with those applied by EPA in preparing the 1999 NEI and the 2002 NEI (Pechan, 2006b). In addition to providing a complete reporting of filterable and condensable PM emissions, this augmentation step also fills in PM_{10} or $PM_{2.5}$ primary emission estimates where they appear to be missing, and converts any situations where $PM_{2.5}$ emissions are greater than PM_{10} emissions. The net result of applying the PM augmentation procedures to the 1990 NEI point source file (non-EGU portion) was a 99 thousand ton increase in PM_{10} primary emissions and a 60 thousand ton decrease in $PM_{2.5}$ primary emissions.

Another adjustment made to the 1990 NEI non-EGU emissions was to reduce PM emissions from cement kilns. An analysis of 1990 and 2002 criteria pollutant emissions for the cement manufacturing industry showed that PM_{10} emissions in certain States (e.g., New York) were considerably higher in 1990 than in 2002, with no additional State regulations of this pollutant being added during this period (IEc and Pechan, 2006b). PM emissions from cement kilns have been affected by a New Source Performance Standard (NSPS) since 1971. If the plant was built or modified after August 17, 1971, the preheater and bypass exit gases must meet the NSPS opacity limit of 20 percent and a mass emission limit of 0.15 kg/mg of particulate emissions (0.30 lb/ton) of dry kiln feed. Even those plants built prior to 1971 that are not subject to NSPS normally meet these standards for particulate emissions.

Given the above, the 1990 cement kiln PM emissions were re-estimated so that the national emissions were equal to the product of the NSPS PM emissions rate and the daily clinker capacity during 1990 (at 80 percent capacity utilization). The result was a revised 1990 cement kiln PM_{10} national emissions total of 9,936 tons per year.

For $PM_{2.5}$ emissions, the Project Team determined that the 1990 NEI did not accurately measure emissions from both area and non-EGU point sources. For some emissions categories (e.g., construction) the 1990 estimates were biased high, while for others (e.g., commercial cooking) the 1990 emissions estimates were biased low because estimation methods did not exist in 1990 for those categories. Using the 1990 NEI to project $PM_{2.5}$ emissions from non-EGU point sources in the *without-CAAA* scenario would therefore overestimate the impact of the CAAA for some source categories while creating erroneous estimates of disbenefits for other source categories. To address this issue, the Project Team opted to take a conservative approach of assuming no impact of the CAAA on $PM_{2.5}$ emissions from non-EGU point sources, by setting *without-CAAA* emissions equal to *with-CAAA* emissions.

EMISSION SUMMARY BY SCENARIO

Exhibit 3-4 summarizes the national (48 State) results of the non-EGU point source analysis for 2002, 2010, and 2020. Comparisons of *with*- versus *without-CAAA* criteria pollutant emissions are generally according to expectations – as *with-CAAA* emissions in 2000, 2010, and 2020 are normally less than *without-CAAA* emissions. Several exceptions can be noted in some of the smaller emitting categories for all pollutants, for example in some cases emissions of NOx, VOC, CO, or SO2 are somewhat higher in the *with-CAAA* case for the solvent utilization, waste disposal and recycling, storage and transport, and miscellaneous source categories. In all cases, the net effect of these apparent anomalies is less than 10,000 tons, which is much less than the corresponding reductions attributable to the CAAA that are apparent for other larger emitting and generally well-controlled emissions categories. The Project Team believes that most of the apparent anomalies can be attributed to differences in methods in the 1990 and 2002 NEI that form the basis of the *without-CAAA* and *with-CAAA* scenarios, respectively. Our overall approach has been to attempt to resolve these discrepancies where we believe it may have a potentially large effect on the air quality and subsequent benefits estimation steps. For example, in the draft report, large apparent anomalies in the ammonia inventories were investigated and found to reflect major differences in EPA's and state's understanding of ammonia emissions rates and the corresponding activity factors. Resolving all the remaining anomalies, however, would be very resource intensive and would not likely be a cost-effective use of project resources. The Project Team believes that the effect of this factor is to contribute to a potential underestimation of the benefits of the CAAA for non-EGU point sources, though that underestimation is likely to be small.

The *with-CAAA* VOC emission projections for this sector show an overall 3 percent increase in VOC emissions from 2002 to 2010 and a 14 percent increase from 2010 to 2020. For VOC emissions, there is no dominant source category. This is a sector where many of the sources added controls in the 1990 to 2000 period in response to EPA NESHAPs. Between 2000 and 2010, there are additional NESHAP requirements for certain source categories like petroleum refineries that produce lower emissions in 2010 than in 2000. However, for most source categories, VOC emissions are estimated to increase from 2000 to 2010. Then, because no additional emission control requirements are imposed after 2010, *with-CAAA* VOC emissions in the 2010 to 2020 period increase in proportion to expected activity growth in this period, consistent with our projection approach assuming that, absent new controls, emissions grow with economic or throughput activity.

EXHIBIT 3-4. NATIONAL NON-EGU EMISSIONS BY MAJOR SOURCE CATEGORY (TPY)

Source Category	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
VOC							
Fuel Comb. Industrial	165,662	177,006	133,400	207,797	136,383	241,842	148,432
Fuel Comb. Other	8,495	9,442	10,646	15,500	10,301	16,918	11,595
Chemical & Allied Product	460,077	508,151	130,623	559,123	134,212	634,625	156,710
Metals Processing	121,909	147,034	45,613	149,881	46,652	159,859	52,207
Petroleum & Related Industrial	254,433	286,604	128,706	333,979	140,383	368,163	152,023
Other Industrial Processes	339,726	420,299	387,503	492,266	407,430	588,640	471,484
Solvent Utilization	886,454	1,103,531	350,069	1,209,716	315,642	1,415,475	372,853
Storage & Transport	336,269	376,958	190,047	434,337	217,916	496,116	249,152
Waste Disposal & Recycling	35,759	47,702	23,648	58,976	24,685	75,862	30,938
Miscellaneous	584	871	2,088	1,223	1,871	1,702	2,156
Total	**2,609,368**	**3,077,597**	**1,402,343**	**3,462,797**	**1,435,475**	**3,999,199**	**1,647,551**
NO_x							
Fuel Comb. Industrial	2,177,807	2,217,681	1,508,067	2,292,812	1,398,388	2,565,989	1,534,243
Fuel Comb. Other	145,311	161,238	108,991	170,931	103,702	188,912	117,822
Chemical & Allied Product	164,330	168,118	67,544	182,803	69,657	209,829	86,446
Metals Processing	97,996	117,566	66,161	123,618	73,598	133,771	79,774
Petroleum & Related Industrial	133,024	167,125	61,610	194,300	59,123	208,455	63,699
Other Industrial Processes	374,790	449,327	417,012	530,599	479,254	613,489	550,009
Solvent Utilization	1,246	1,506	6,669	1,648	2,402	1,975	2,861
Storage & Transport	1,682	2,435	11,838	2,658	13,923	3,298	16,451
Waste Disposal & Recycling	37,265	46,312	43,694	56,504	45,766	71,557	56,809
Miscellaneous	0	0	723	0	807	0	926
Total	**3,133,450**	**3,331,308**	**2,292,311**	**3,555,874**	**2,246,621**	**3,997,276**	**2,509,040**
CO							
Fuel Comb. Industrial	693,720	752,560	990,211	928,396	1,088,782	1,095,402	1,199,142
Fuel Comb. Other	169,993	181,770	90,683	204,735	102,154	212,363	115,664
Chemical & Allied Product	1,183,331	1,303,012	282,040	1,308,657	341,814	1,435,083	426,360
Metals Processing	2,639,651	3,056,458	986,401	3,010,166	913,608	3,087,657	973,830
Petroleum & Related Industrial	328,301	443,318	102,832	518,757	79,537	583,194	84,472
Other Industrial Processes	535,747	587,737	454,678	686,670	554,875	787,116	635,749
Solvent Utilization	4,523	4,471	1,503	4,865	1,738	5,098	2,065
Storage & Transport	75,464	90,497	117,600	89,058	115,082	102,000	128,964
Waste Disposal & Recycling	36,674	47,032	85,696	56,945	92,173	73,765	109,963
Miscellaneous	0	0	987	0	1,042	1	1,227
Total	**5,667,404**	**6,466,855**	**3,112,631**	**6,808,250**	**3,290,804**	**7,381,679**	**3,677,434**

Source Category	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
SO_2							
Fuel Comb. Industrial	2,218,863	1,884,797	1,038,889	2,118,986	978,660	2,203,475	1,002,950
Fuel Comb. Other	204,683	137,583	90,928	147,545	91,493	150,582	90,539
Chemical & Allied Product	296,686	353,586	257,923	368,170	245,043	424,809	311,473
Metals Processing	725,409	717,183	208,684	662,400	231,981	765,381	265,906
Petroleum & Related Industrial	428,029	516,734	253,524	606,263	238,508	664,633	266,179
Other Industrial Processes	395,788	459,430	323,120	546,988	371,149	615,695	425,934
Solvent Utilization	317	369	188	400	185	454	206
Storage & Transport	1,748	2,321	4,441	2,654	4,879	3,100	5,528
Waste Disposal & Recycling	21,747	27,584	15,251	33,861	14,926	43,404	18,341
Miscellaneous	0	0	264	0	276	0	311
Total	**4,293,268**	**4,099,586**	**2,193,213**	**4,487,265**	**2,177,099**	**4,871,531**	**2,387,367**
PM_{10}							
Fuel Comb. Industrial	349,771	358,630	123,023	407,281	112,990	461,666	126,966
Fuel Comb. Other	23,523	21,308	10,523	21,945	10,084	23,515	11,354
Chemical & Allied Product	142,921	166,884	33,901	168,502	39,064	190,210	46,603
Metals Processing	451,223	556,978	79,208	573,850	68,015	630,200	75,706
Petroleum & Related Industrial	70,029	73,103	23,339	85,721	24,461	98,640	28,189
Other Industrial Processes	558,425	670,788	245,232	755,608	249,307	869,451	299,552
Solvent Utilization	4,198	5,831	6,312	6,704	6,522	7,808	7,617
Storage & Transport	118,162	138,514	58,218	155,021	53,778	174,366	62,177
Waste Disposal & Recycling	16,558	21,655	17,286	27,180	17,506	35,249	22,660
Miscellaneous	0	0	832	0	907	0	1,035
Total	**1,734,810**	**2,013,691**	**597,875**	**2,201,812**	**582,635**	**2,491,106**	**681,858**
$PM_{2.5}$							
Fuel Comb. Industrial	88,540	88,540	88,540	86,323	86,323	96,291	96,291
Fuel Comb. Other	7,680	7,680	7,680	8,002	8,002	9,051	9,051
Chemical & Allied Product	24,628	24,628	24,628	29,688	29,688	36,174	36,174
Metals Processing	50,981	50,981	50,981	49,969	49,969	54,913	54,913
Petroleum & Related Industrial	16,956	16,956	16,956	19,115	19,115	21,704	21,704
Other Industrial Processes	135,830	135,830	135,830	155,859	155,859	181,251	181,251
Solvent Utilization	4,996	4,996	4,996	5,574	5,574	6,477	6,477
Storage & Transport	22,104	22,104	22,104	24,455	24,455	27,125	27,125
Waste Disposal & Recycling	13,149	13,149	13,149	14,524	14,524	17,695	17,695
Miscellaneous	396	396	396	433	433	489	489
Total	**365,260**	**365,260**	**365,260**	**393,943**	**393,943**	**451,169**	**451,169**

Source Category	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
NH_3							
Fuel Comb. Industrial	9,952	10,935	3,983	11,770	4,351	13,384	4,879
Fuel Comb. Other	256	167	470	139	583	152	622
Chemical & Allied Product	182,577	168,067	22,501	163,208	24,534	171,819	28,470
Metals Processing	5,901	7,522	3,243	7,477	3,092	7,619	3,068
Petroleum & Related Industrial	42,845	47,741	2,664	53,309	3,104	61,033	3,555
Other Industrial Processes	2,084	1,693	117,053	1,555	133,510	1,630	155,137
Solvent Utilization	0	0	236	0	254	0	272
Storage & Transport	0	0	709	0	764	0	794
Waste Disposal & Recycling	0	0	3,047	0	3,709	0	4,815
Miscellaneous	0	0	38	0	45	0	57
Total	**243,615**	**236,126**	**153,944**	**237,459**	**173,946**	**255,636**	**201,670**

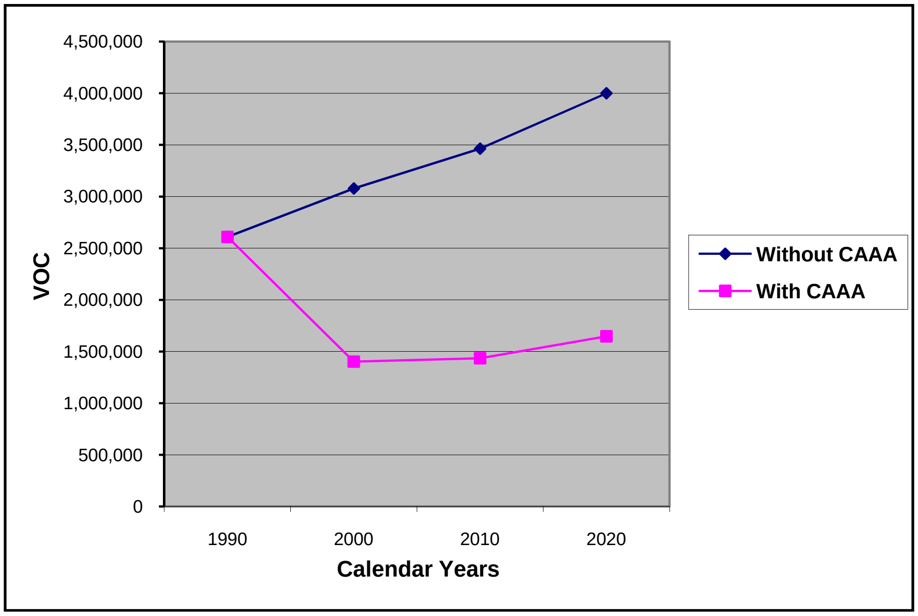
In interpreting our NO_x emissions results, it is important to remember that non-EGU point source NO_x emissions are a product of fuel combustion. In the eastern United States, many of the large fuel combustion sources are subject to the requirements of the NO_x SIP Call, and these requirements affect industrial boiler, gas turbine, RICE engine, and cement kiln emissions starting after 2002. Outside the NO_x SIP Call area, there are stringent NO_x rules affecting NO_x sources in eastern Texas, the Baton Rouge area in Louisiana, and in many Air Districts in California. Sources and geographic areas affected by these requirements contribute to the expected emission reductions between 2000 and 2010. After 2010, some NO_x emission increases are anticipated as fuel consumption by the industrial sector continues to grow. Uncertainties in the NO_x emission projections include whether NO_x SIP Call States include their affected non-EGU boilers and gas turbines as trading program sources, whose NO_x emissions are effectively capped, and whether sources affected by a 5 month ozone season control program install controls that also reduce NO_x emissions during the 7 month winter season.

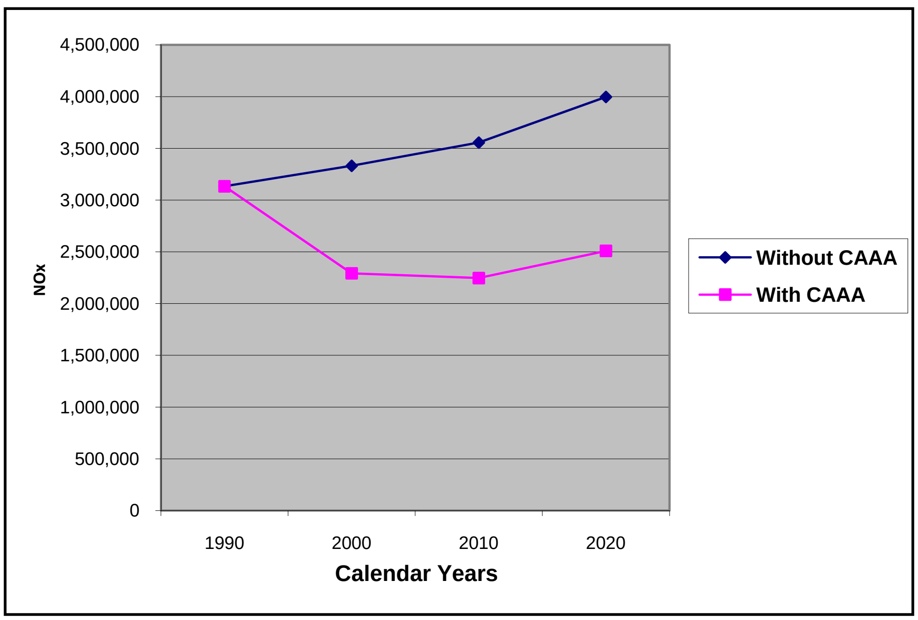
Non-EGU SO_2 emissions are expected to stay relatively stable over the forecast period. Industrial fuel combustion SO_2 emissions from boilers decline slightly from 2000 to 2010, and then increase to near 2000 levels by 2020. The slight upward trend in non-EGU SO_2 emissions over the forecast period is a result of strong expected activity growth in the chemical industry and other industrial processes. Some industries, such as copper smelting, that have historically been major SO_2 emission contributors, are now modest contributors to non-EGU SO_2 emissions, and have little influence on future national SO_2 emissions in this sector. Refinery settlements produce SO_2 emission reductions in the forecast period for the petroleum industry.[25]

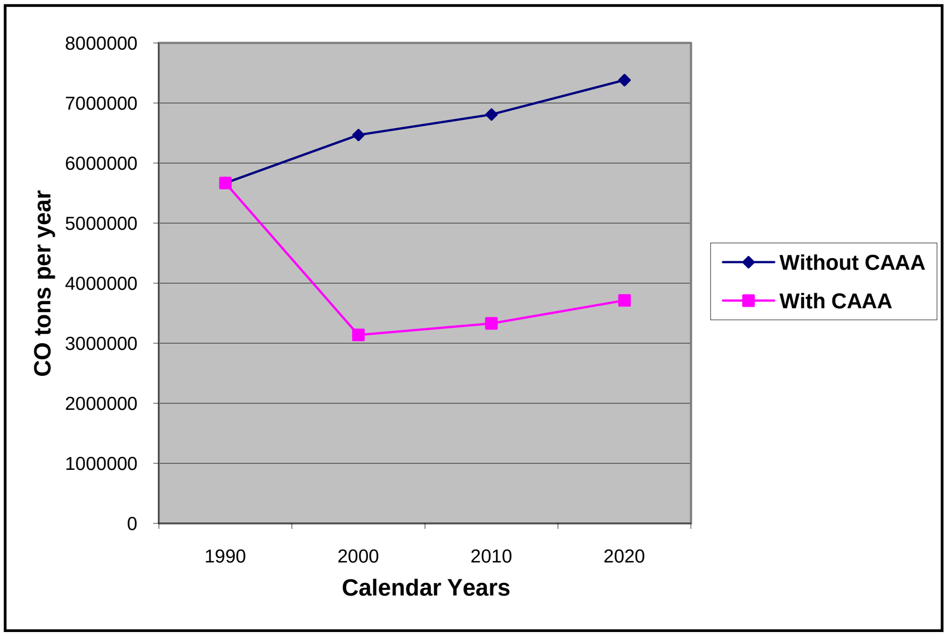
Exhibit 3-5 displays the non-EGU point source sector *with*- and *without-CAAA* emission summaries by pollutant in a graphic format. Because *without-CAAA* $PM_{2.5}$ emissions are assumed to be equal to *with-CAAA* emissions, they are not included in the exhibit.

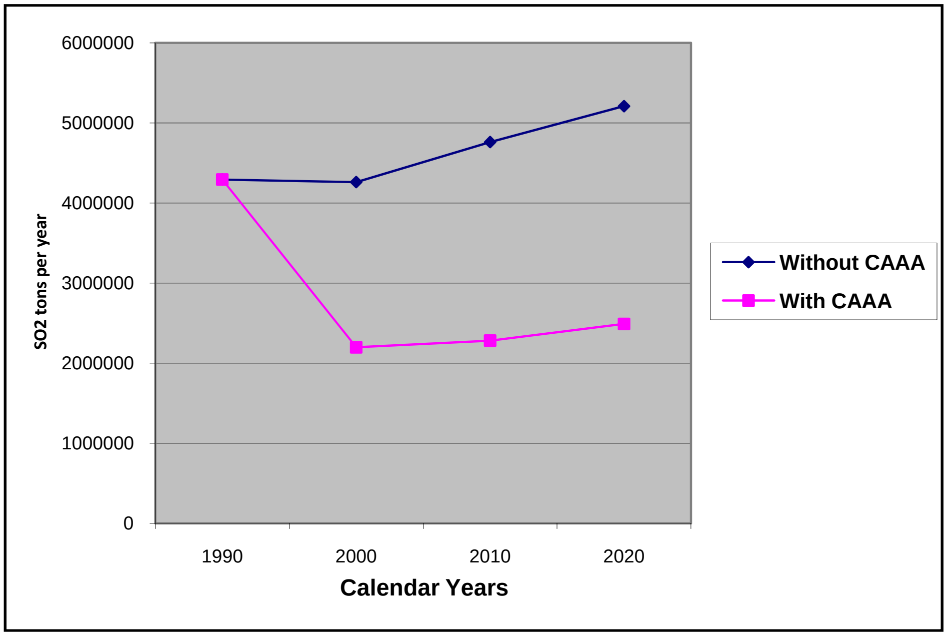
[25] Note that the non-EGU SO2 emission projections do not include any influence of best available retrofit technology (BART) controls. BART controls are addressed as part of the local controls analysis, described in Chapter 8.

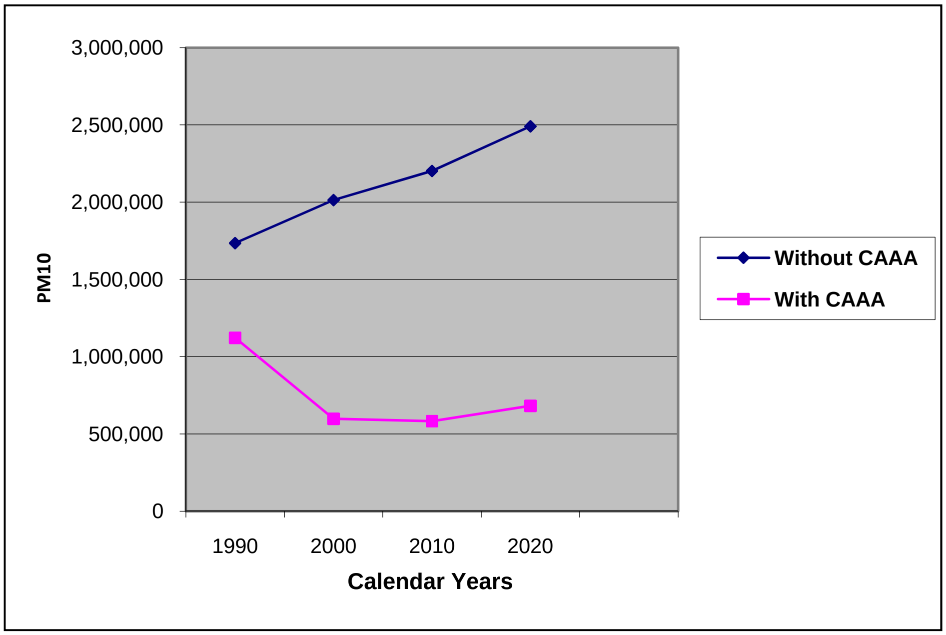
EXHIBIT 3-5. *WITH-* AND *WITHOUT-CAAA* SCENARIO NON-EGU POINT SOURCE EMISSION SUMMARIES BY POLLUTANT

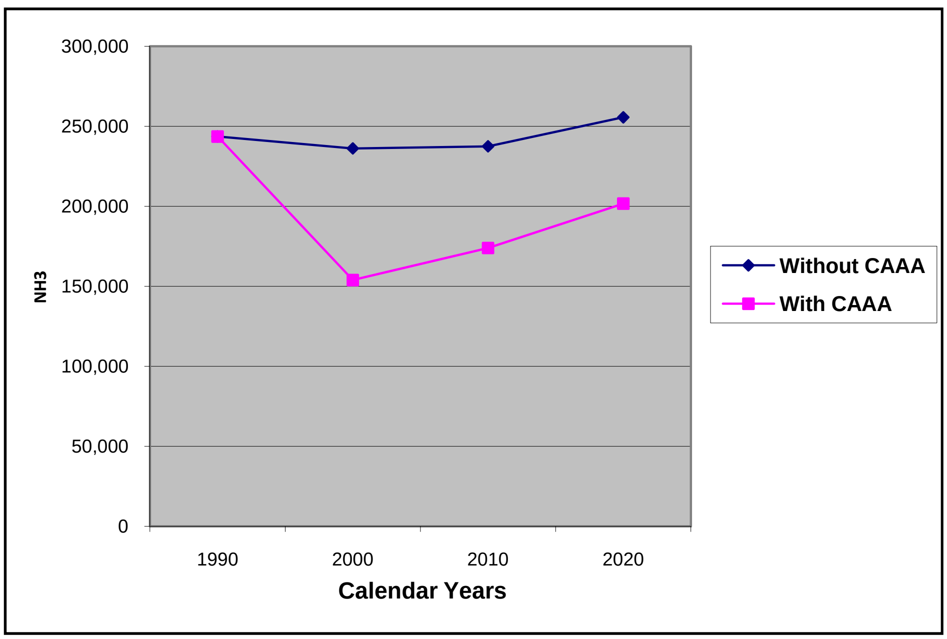





8000000
7000000
6000000
5000000
4000000
3000000
2000000
1000000
0
CO tons per year
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


6000000
5000000
4000000
3000000
2000000
1000000
0
SO2 tons per year
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
PM10
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


300,000
250,000
200,000
150,000
100,000
50,000
0
NH3
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA

CHAPTER 4 | ELECTRICITY GENERATING UNIT POINT SOURCES

OVERVIEW OF APPROACH

The Clean Air Act Amendments (CAAA) of 1990 significantly expanded EPA's authority to regulate emissions from U.S. electric utilities and established a new approach to air pollution regulation in the U.S. Since the passage of the Amendments, EPA has developed several new regulations governing utility emissions of SO_2, NO_x, mercury, and other pollutants. Although several of these rules rely on command-and-control mechanisms to limit EGU emissions, Title IV of the Amendments established a market-based cap-and-trade system for reducing emissions of SO_2 from electric utilities. Similarly, under Title I of the Amendments, EPA established a cap-and-trade system for NO_x to limit inter-regional transport of ozone. Under these cap-and-trade systems, EPA sets annual emissions caps for both SO_2 and NO_x and issues a limited number of tradable emissions allowances to affected sources authorizing them to emit one ton of SO_2 or NO_x per allowance. Emissions for the EGU sector in aggregate must stay within the cap, but individual sources are free to trade emissions allowances among themselves, encouraging the utility sector to reduce emissions at those sources that can most cost-effectively limit their emissions. Similar to the market-based programs for SO_2 and NO_x, EPA has also established a cap-and-trade system for mercury under which utilities may trade emissions allowances to determine which facilities will most aggressively control their mercury emissions. To supplement CAAA-related regulations, several states have also established their own emissions requirements for utilities since the passage of the Amendments in 1990. For example, the state of California is regulating NO_x and CO emissions from utility boilers located in the Bay Area Air Quality District (BAAQD) in an effort to bring the District into attainment with the National Ambient Air Quality Standards (NAAQS) for ozone.[26]

The purpose of this chapter is to describe the Project Team's approach for estimating the impact of the Clean Air Act Amendments on EGU emissions between 1990 and 2020 and to present the Project Team's estimates of these impacts. We focus on EGUs separately from other point sources because of the significance of the cap-and-trade programs outlined above and because of the magnitude of EGU emissions relative to emissions from other sources. According to EPA's 2002 National

[26] California's state implementation plan for the ozone NAAQS includes NO_x and CO emissions requirements for EGU steam boilers in the BAAQD with a capacity of at least 250 million Btu per hour. *Federal Register*, Volume 67, Number 97, May 20, 2002, pages 35434-35437.

Emissions Inventory, EGUs were responsible for 67 percent of total SO_2 emissions in 2002 and 22 percent of NO_x emissions.[27]

We present the study's methodology and results in four separate sections. First, we provide a detailed description of the analytic tools the Project Team used to estimate EGU emissions. In the second and third sections, we describe the application of these tools. We present this information in two separate sections because the approach for estimating emissions retrospectively is different from the approach used to project emissions into the future. To conclude the chapter, we present the Project Team's emissions estimates for the four target years selected for the Second Prospective: 1990, 2000, 2010, and 2020.[28]

Edited footnote → Although the Second 812 Prospective study estimates the impacts of the Amendments for the years 2000, 2010, and 2020, EGU emissions in 2001 were adopted as a proxy for emissions in 2000. Before commencing with the emissions analysis for the Second Prospective, EPA conducted an analysis of EGU emissions in 2001 to test the accuracy of the analytic tools that EPA typically uses for EGU emission analyses. Due to resource constraints, the Project Team decided to expand upon this analysis for the Second Prospective rather than developing an entirely new EGU emissions analysis for 2000.

ANALYTIC TOOLS

To assess CAAA-related emissions impacts for NO_x, SO_2, and mercury, the study applies the Integrated Planning Model (IPM) developed by ICF Resources, Inc. IPM is a dynamic, linear programming model of the electric power sector that represents several key components of energy markets (i.e., markets for fuels, emissions allowances, and electricity) and the linkages between them. The model determines the utility sector's least-cost strategy for meeting energy and peak demand requirements over a specified period of time, accounting for a number of regulatory and non-regulatory constraints. (e.g., emissions caps and transmission constraints). In this section, we summarize the structure, features, and assumptions of IPM; the key outputs generated by the model; and recent EPA efforts to assess the validity of IPM's results.

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[27] 2002 NEI as cited in U.S. EPA, "Acid Rain Program 2003 Progress Report," September 2004, EPA 430-R-04-009.

[28] Although the Second Prospective will estimate the impacts of the Amendments for the years 2000, 2010, and 2020, the Project Team uses EGU emissions in 2001 as a proxy for emissions in 2000. Before commencing with the emissions analysis for the Second Prospective, EPA conducted an analysis of EGU emissions in 2001 to test the accuracy of the analytic tools that EPA typically uses for EGU emission analyses. Due to resource constraints, the Project Team expanded upon this analysis for the Second Prospective rather than developing an entirely new EGU emissions analysis for 2000.

IPM STRUCTURE, FEATURES, AND ASSUMPTIONS[29]

As a linear programming model, IPM is structured around an objective function that represents the net present value of the costs of meeting U.S. electricity demand over IPM's model time horizon. To reach a solution for a given model scenario, IPM minimizes its objective function subject to a number of regulatory and non-regulatory constraints. These constraints include emissions caps, the capacity of each unit, transmission constraints, reserve margins, turn down constraints (i.e., whether a unit can shut down at night), and the compatibility of individual fuels with different generating technologies. Accounting for these constraints and the characteristics of the units included in the model, IPM endogenously models utility dispatch decisions, capacity additions, and retirements to minimize the value of its objective function. In doing so, IPM takes electricity demand as exogenous rather than estimating how demand might change in response to changes in electricity prices. IPM also assumes that utilities operate in an environment of perfect competition and that they have perfect foresight of future constraints. As IPM models dispatch based on these future constraints and other information, it does not factor sunk investments into its optimization process. Therefore, the model's cost outputs do not reflect the annualized cost of CAAA-related investments made prior to the model time horizon.[30]

To simulate the behavior of the electric utility sector over the model time horizon, IPM simulates the operation of several model plants for a limited number of model run years instead of modeling each unit in the U.S. individually for every year in the model time horizon. The model plants included in IPM may represent aggregations of existing units with similar characteristics; new plants constructed over the model time horizon; or retrofit, re-powering, and retirement options available to existing units. Similarly, each model run year included in IPM (2007, 2010, 2015, and 2020) represents a multi-year period in IPM's planning horizon.[31] Although IPM reports results for a limited number of model run years, it takes investment decisions into account for each year in the model's planning horizon. For example, the model results for 2020 reflect utility investments in retrofit capital in 2009.

Similar to its representation of model plants and model run years, IPM spatially divides the U.S. electricity market into 26 model regions corresponding broadly to the North American Electric Reliability Council (NERC) regions. Based on historical demand data for each region and EPA projections of electricity demand, IPM includes a series of seasonal load duration curves specific to each region and

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[29] This section is based on information presented in U.S. EPA, *Standalone Documentation for EPA Base Case 2004 (V2.1.9) Using the Integrated Planning Model*, September 2005, EPA 430-R-05-011.

[30] Because IPM's results do not reflect costs associated with pre-2007 investments, the Project Team conducted an analysis offline to estimate these costs. The Project Team addresses this issue in more detail in the cost report for the Second Prospective.

[31] IPM also includes 2026 as a model run year, but EPA does not typically report the results for this year. Because 2026 is the last model run year in IPM's planning horizon, the results for 2026 may be skewed.

model run year. IPM uses this information to simulate the dispatch of each model plant and the transmission of electricity within and between each model region.

IPM OUTPUTS

IPM generates several outputs relevant to the Second Prospective. These include the following:

NO_x, SO_2, Mercury, and Carbon Dioxide Emissions: IPM estimates emissions of NO_x, SO_2, mercury, and carbon dioxide for each model run year in aggregate and at the unit level.

***Costs*:** Based on the simulated dispatch, retrofit, retirement, and plant construction decisions simulated in IPM, the model estimates annual capital costs, fixed operating and maintenance (O&M) costs, and variable O&M costs in aggregate and at the unit level.

***Capacity and Generation*:** Under any given regulatory scenario, IPM estimates capacity and generation by fuel type for each model run year in IPM's planning horizon.

***Fuel and Electricity Prices*:** Based on IPM's least-cost strategy for meeting electricity demand, the model endogenously estimates coal, natural gas, and electricity prices by model run year.

***Allowance Prices*:** IPM estimates allowance prices for SO_2, NO_x, and mercury. These estimates reflect the regulatory constraints included in the model, the characteristics of affected sources, and the costs of the control technologies associated with each pollutant.

IPM PEER REVIEW AND MODEL VALIDATION

Because IPM is a proprietary model, it has not undergone a comprehensive peer review. In 2003, however, EPA organized an independent review of the natural gas supply curves included in the model. In addition, EPA periodically conducts validation analyses to test the credibility of IPM's results.

PEER REVIEW OF IPM'S NATURAL GAS SUPPLY CURVES[32]

On October 23-24, 2003 EPA convened a panel of eight independent experts for a peer review of the natural gas assumptions used in EPA's applications of IPM. Based on the recommendations of the peer review panel and detailed supply and demand data obtained from the National Petroleum Council's 2003 Natural Gas Study, EPA subsequently updated the assumptions underlying the natural gas supply curves that were developed for EPA Base Case 2004. These changes include the following:

[32] The discussion of EPA's natural gas supply curves presented in this section is based on the summary presented in chapter 8 of U.S. EPA, *Standalone Documentation for EPA Base Case 2004 (V2.1.9) Using the Integrated Planning Model*, September 2005, EPA 430-R-05-011.

Resource Data and Reservoir Description: A complete update to the undiscovered natural gas resource base for the Western Canada Sedimentary Basin (WCSB) and key regional updates within the U.S. were completed as new data became available in 2002 and 2003. For the U.S., the primary data sources were the United States Geological Survey (USGS) and the Minerals Management Service (MMS). ICF investigated the conventional resource assessment of the Canadian Gas Potential Committee (CGPC), unconventional resource assessments published by the Alberta Energy Utilities Board (AEUB), publicly available reports, and information available from the provincial energy departments for Saskatchewan and British Columbia. Key updates included:

- Reviewing assumptions regarding conventional resource plays and, where warranted, modifying the internal field size distribution procedure so that the maximum undiscovered field size did not exceed the maximum undiscovered field size class estimates of the USGS for corresponding assessment units.[33]
- Reducing well spacing assumptions to reflect current production practices.
- Where new data were available, updating reservoir parameters such as average depth and gas composition.
- Comparing and calibrating modeled production trends in the Rocky Mountain and Gulf Coast regions with recent established history, using regional natural gas production reports from Lippman Consulting, Inc.
- Substantially re-categorizing and updating undiscovered Canadian resources based on recent estimates published by CGPC, including a complete update of undiscovered resources for established plays in the Western Canadian Sedimentary Basin.

Treatment of Frontier Resources: Using a variety of publicly available data sources, ICF updated the representation of Alaska North Slope, Mackenzie Delta, Sable Island, and existing and potential liquefied natural gas (LNG) terminals in the North American Natural Gas Analysis System (NANGAS), the model used to generate the natural gas supply curves for EPA Base Case 2004.

Exploration and Production (E&P) Characterization: Among the key revisions in E&P characterization that resulted from the peer review process were:

- Increasing the required rate of return (hurdle rate) from 10 percent to 15 percent for exploration projects and 12 percent for development projects.
- Setting success rate improvement assumptions of 0.5 percent per year for onshore projects and 0.8 percent per year for offshore projects.

[33] A resource play is an accumulation of hydrocarbons known to exist over a large area.

- Establishing operating cost decline rates of 0.54 percent per year and drilling cost decline rates of 1.9 percent per year for onshore and 1.2 percent per year for offshore.
- Making use of the research and development (R&D) program evaluation undertaken by the U.S. Department of Energy's Strategic Center for Natural Gas to identify key technology levers and advancement rates.

Natural Gas Demand: The supply of natural gas available to utilities in IPM is calculated as the total amount of gas supplied at a given Henry Hub price minus the total volume consumed by non-EGU consumers at that price. The relationships between the Henry Hub price and total supply and between the Henry Hub price and non-EGU demand are estimated outside of IPM in NANGAS, but IPM uses these relationships to estimate the amount of natural gas available to utilities. Based on the peer review recommendations, the following improvements were made to the NANGAS representation of end use demand used to estimate the amount of natural gas available for utilities in IPM:

- Capturing demand destruction in the industrial feedstock sector by incorporating into NANGAS the natural gas demand forecasts for the feedstock and process heat sectors developed for the NPC natural gas study.
- Revising the macroeconomic equations used to generate the estimates of residential and commercial sector demand for natural gas and capturing income elasticity in the estimates of residential demand.

VALIDATION ANALYSES

To supplement the peer review of the natural gas supply curves included in IPM, EPA periodically conducts its own analyses to test the validity of the model's results. EPA performed such an analysis to examine the accuracy of IPM's dispatching of EGU generating capacity. To conduct this analysis, EPA populated IPM with 2001 data for several key variables: generating capacity by fuel type, Henry Hub natural gas prices, load duration curves for each IPM model region, and electricity demand. EPA included 2001 capacity and retrofit investments in the model for the purposes of the analysis, but restricted IPM from making any investment decisions. This ensured that the capital reflected in the model's simulation of plant dispatch was consistent with the EGU capital stock in place in 2001. After running IPM under these conditions, EPA compared the model's generation and emissions results to actual generation and emissions data for 2001.[34] Overall, IPM's estimates for each plant type were within ten percent of the actual values. This result suggests that IPM's methodology for minimizing generating costs subject to operational and regulatory constraints represents a reasonable approximation of actual dispatch decisions.

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[34] EPA compared IPM's generation estimates to EIA estimates for this analysis. IPM's emissions estimates for SO_2 and NO_x were compared to values presented in U.S. EPA, "EPA Acid Rain Program 2001 Progress Report," November 2002.

In addition to the validation analysis conducted for 2001, EPA evaluates the accuracy of IPM's results during the development of each new EPA Base Case (i.e., for each model update). More specifically, EPA examines whether IPM's Base Case results for the earliest model run year reasonably reflect the historical operation of the electric power system. Model outputs checked against recent historical data include the following:

- Regional capacity and generation by major generator type (coal, oil/gas steam, etc.);
- Regional capacity factors for each major generator type. In addition to comparing IPM's estimates to historical data, EPA determines whether they are consistent with planned retirements and capacity additions and with expectations of future capacity availability;
- Fuel consumption by type (e.g., coal and gas) and by coal rank (e.g., bituminous);
- Inter-regional transmission, and
- Wholesale electricity prices for each IPM region.

If IPM's near-term projections for any of these variables differ significantly from recent historical values, EPA re-evaluates and, as necessary, modifies the model's inputs, assumptions, and structure.

ESTIMATION OF EMISSIONS FOR POLLUTANTS NOT INCLUDED IN IPM

To estimate emissions of pollutants not included in IPM, the study applied EPA-approved procedures for post-processing the output data generated by IPM version 2.1.9. Using this methodology, the Project Team estimated EGU emissions of CO, VOC, PM_{10}, $PM_{2.5}$, and NH_3 as a function of the estimated fuel consumption for each unit, the content of the fuel consumed by each unit, the emissions factor for each pollutant, and the estimated control efficiency for each pollutant (PM_{10} and $PM_{2.5}$ only). Equations 1 and 2 summarize how this information was applied in this analysis.

(1) $$E_{CO,VOC,NH3} = FC \times EF_{CO,VOC,NH3}$$

(2) $$E_{PM10,PM2.5} = FC \times EF_{PM10,PM2.5} \times A \times (1 - CE)$$

Where $E_{CO,VOC,NH3}$= Emissions of CO, VOC, or NH_3,

FC= Fuel consumption,

$EF_{CO,VOC,NH3}$= Emissions factor for CO, VOC, or NH_3,

$E_{PM10,PM2.5}$=Emissions of PM_{10} or $PM_{2.5}$,

$EF_{PM10,PM2.5}$=Emissions factor for PM_{10} or $PM_{2.5}$,

A= Ash content, and

CE=Control efficiency.

Following the methodology summarized in Equations 1 and 2, the study applied the fuel consumption estimates generated by IPM and modified estimates of EPA's AP-42 emission factors approved by the Agency's Office of Air Quality Planning & Standards as of August 2003. These modified emission factors are used for both the *with-CAAA* and *without-CAAA* scenarios. The ash content for each unit was then calculated based on the weighted average of the monthly values reported on each unit's 2001 EIA-767 form. For PM_{10} and $PM_{2.5}$ control efficiencies, the same values selected by EPA for the development of the 2002 National Emissions Inventory were used. For each control technology, these values are the same for both the *with-CAAA* and *without-CAAA* scenarios.

Under the methodology outlined in Equations 1 and 2 above, the difference between *with-CAAA* and *without-CAAA* EGU emissions of CO, VOC, and NH_3 depends only on the difference in the fuel mix between scenarios. Utilities do not control emissions of these pollutants under either scenario, and controls for SO_2, NO_x, and mercury do not limit CO, VOC, or NH_3 emissions. In contrast, the difference between *with-CAAA* and *without-CAAA* emissions of particulate matter (PM_{10} and $PM_{2.5}$) depends on both the fuel mix and the control technologies installed for SO_2 and NO_x under each scenario. The technologies that utilities use to control SO_2 and NO_x emissions reduce emissions of both PM_{10} and $PM_{2.5}$.

IPM ANALYSES FOR 2010 AND 2020

This section describes the *with-CAAA* and *without-CAAA* scenarios developed for the 2010 and 2020 IPM analyses and the core data inputs included in the model. Because IPM analysis for the 2000 target year differs significantly from the 2010 and 2020 analyses, we present the methodology for the 2000 analysis in a separate section below.

REGULATORY SCENARIOS FOR 2010 AND 2020

As described in Chapter 1, the *with-CAAA* scenario reflects all federal, state, and local regulations affecting utilities that have been promulgated since the passage of the Amendments in 1990. These include the following:

- The Clean Air Interstate Rule,
- The Clean Air Mercury Rule,
- SIP Call Post-2000,
- Reasonably Available Control Technology (RACT) and New Source Review requirements for all non-waived (NO_x waiver) non-attainment areas,
- Phase II of the Ozone Transport Commission (OTC) NO_x memorandum of understanding,[35]

[35] Under Phase II of the OTC memorandum of understanding, eleven eastern states committed themselves to achieving regional reductions in NO_x emissions through a cap-and-trade system similar to the SO_2 trading program established

- Title IV Phase I and Phase II limits for all boiler types,
- 25-ton Prevention of Significant Deterioration (PSD) regulations and New Source Performance Standards (NSPS),
- Title IV emission allowance program,
- Utility emissions caps set by individual states (CT, MA, MO, NH, NC, TX, and WI), and
- Emissions reductions achieved because of post-1990 enforcement actions (e.g., NSR cases and settlements).

Under the *without-CAAA* scenario, federal, state, and local controls of utility emissions are frozen at 1990 levels of scope and stringency. Exhibit 4-1 presents the emissions rates and other assumptions reflected in the *without-CAAA* scenario.

EXHIBIT 4-1. ASSUMPTIONS REFLECTED IN THE *WITHOUT-CAAA* SCENARIO

Element		Assumption
Existing Coal Facilities	SO_2 Rate	• Primary data source:[1] 1990 actual SO_2 emissions rate from U.S. EPA, *Clean Air Markets Data and Maps* (Based on these rates, fuels are assigned to the generating units in the model). • Secondary source: 1990 SO_2 emissions rate used for the no-CAAA scenario in the First 812 Prospective— provided by EPA as part of the NAPAP analysis. • Default: 1.2 lbs of SO_2/mmBtu of input fuel[2]

	NO_x Rate	• Primary data source:[1] 1994 NO_x RIA rates (RATE90-3.dbf) for all units outside California
		• Secondary source: 1990 NO_x rates used in the no-CAAA scenario for the First 812 Prospective
		• Default:[3]
		  ◦ 0.796 lbs/mmBtu of fuel input for units that came online before 1972 and burn bituminous or sub-bituminous coal
		  ◦ 0.7 lbs/mmbtu of fuel input for units that came online between 1972 and 1978 and burn bituminous or sub-bituminous coal
		  ◦ 0.6 lbs/mmbtu of fuel input for units that came online after 1978 and burn bituminous or sub-bituminous coal
		  ◦ 0.6 lbs/mmbtu of fuel input for units that burn lignite coal
		• California units will retain assumptions from EPA Base Case 2004 (v.2.1.9)

	SO_2 Controls	• Remove scrubbers from all plants that were built in response to CAAA:
		  ◦ Remove scrubbers from units that came online before 1978 and if the scrubber was installed after November 15, 1990.
		  ◦ CEMS 2001 and 2000 EIA 767 used to determine scrubber installation date.
		  ◦ Default: Based on the no-CAAA scenario in the First 812 Prospective

	NO_x Post-Combustion Controls	• Remove all NOx controls, except for those meeting California BACT regulations
	Hg Rate	• Mercury emission modification factors from EPA Base Case 2004 (v.2.1.9)

under Title IV of the Amendments. As an initial step in the development of the OTC trading program, the OTC states; EPA; and representatives from industry, utilities, and environmental groups designed a model rule that identified the key elements of the program. Each OTC state then went through its own regulatory process to develop regulations consistent with the model rule.

Element		Assumption
Existing Oil/Gas Steam Facilities	SO_2 Rate	• Primary data source:[1] 1990 actual SO_2 emissions rates from U.S. EPA, *Clean Air Markets Data and Maps*. (Fuels are assigned in the model based on these rates). • Secondary source: SO_2 emissions rate used in the no-CAAA scenario for the First 812 Prospective. • Default:[2] 0.8 lbs of SO_2/mmbtu of input fuel for oil.

	NO_x Rate	• Primary data source:[1] 1994 NO_x RIA rates for all units outside California
		• Secondary source: 1990 NO_x rates used in the no-CAAA scenario for the First 812 Prospective
		• Default:[3]
		  • 0.39 lbs/mmBtu for units that came online before 1979
		  • 0.2 lbs/mmBtu for units that came online in 1979 or later
		• For California units retain assumptions from EPA Base Case 2004 (v.2.1.9)

	SO_2 Controls	• Remove scrubbers from all plants except those built for NSPS:
		  • Remove scrubbers from units that came online before 1978 and if the scrubbers were installed after November 15, 1990.
		  • CEMS 2001 and 2000 EIA 767 used to determine scrubber installation date.
		  • Default: Based on the no-CAAA scenario for the First 812 Prospective.

	NO_x Post-Combustion Controls	• Remove all NOx controls, except for those meeting California BACT regulations
	Hg Rate	• Mercury emission modification factors from EPA Base Case 2004 (v.2.1.9)
Existing Combustion Turbines		• Retain NO_x rates and controls from EPA Base Case 2004 (v.2.1.9)
Existing Combined Cycles		• Retain NO_x rates and controls from EPA Base Case 2004 (v.2.1.9)
Other Existing Units		• All assumptions based on EPA Base Case 2004 (v.2.1.9)
Potential Units (units online 2004 and later)	Coal[2,3]	• Achieves SO_2 rate of 1.2 lbs/mmbtu: plant will include scrubber and option to burn high sulfur coals--for conventional pulverized coal (CPC), integrated gasification combined cycle (IGCC), and combined cycle (CC). • Includes cost & performance of less efficient SCR/SNCR. (IGCC and CPC) • All other cost & performance assumptions based on AEO 2005. • NOx rate of 0.1 lbs/mmbtu for IGCC and 0.3 lbs/mmbtu for CPC
	Combustion Turbine and Advanced Combustion Turbine	• All cost & performance assumptions based on AEO 2005; NO_x rate of 0.1 lbs/mmbtu
	Combined Cycle and Advanced Combined Cycle	• Include cost & performance of less efficient SCR; Achieves NO_x rate of 0.1 lbs/mmbtu.
	Oil/Gas Steam Units	• Consistent with EPA Base Case 2004 (v.2.1.9) no new Oil/Gas steam option will be provided
	Renewables	• All cost and performance assumptions based on AEO 2005
Environmental Regulations		• No emission constraints representing CAAA-related environmental regulations are included. • No NSR settlements implemented in EPA Base Case 2004 (v.2.1.9) are included.
Coal supply curves and other fuel assumptions		• Retain coal supply restrictions assumed in the no-CAAA scenario for the First 812 Prospective • All other assumptions, excluding coal supply restrictions, from EPA Base Case 2004 (v.2.1.9) • Coal productivity assumptions from AEO 2005 will be incorporated.
Other Assumptions		• Unless otherwise mentioned, all other assumptions based on EPA Base Case 2004 (v.2.1.9)

Element	Assumption
Notes: 1. If a unit's emissions rate for 1990 was available from the primary data source, we assigned the unit the emissions rate from this source. If a unit's 1990 emissions rate was not available from the primary source but was available from the secondary source, we used the rate from the secondary source. Otherwise, we used the default emissions rate. 2. Default SO_2 rates for existing units and assumed emission rates new units are based on NSPS standard described in 40 CFR Ch. 1 (7-1-98) Subpart D §60.43 and 40 CFR Ch. 1 (7-1-98) Subpart Da §60.43a. The SO_2 NSPS emissions standard is differentiated between plants that commenced construction after 1971 and plants that commenced construction after 1978. In the modeling, we have assumed that the cutoff dates apply to online years rather than dates on which construction was initiated. For plants that commenced construction after 1978, the standard gives coal plants the additional option to achieve a rate of 0.6 lbs/mmbtu with control efficiency of 70%. The assumptions do not include this option. 3. NO_x rates for existing units and assumed emission rates new units are based on NSPS standard described in 40 CFR Ch. 1 (7-1-98) Subpart D §60.44 and 40 CFR Ch. 1 (7-1-98) Subpart Da §60.44a. For coal units, the standard makes several distinctions between plants using bituminous, sub-bituminous and lignite coal along with other differences between lignite coal mined in North Dakota, South Dakota and Montana and for cyclone units. For simplicity, the assumed NO_x rates for non-lignite coal in units coming online after 1978 reflects the NO_x rate for bituminous coal. Similarly, the distinction between lignite mined in the three states named above and the rest of the country has been dropped and the assumption includes the NO_x standard for lignite mined outside of the three states. As with SO_2, the proposed assumption uses the online date rather than the construction date as the criteria for the emissions standards.	

INPUT DATA FOR THE 2010 AND 2020 IPM ANALYSES

The IPM emissions analyses conducted for the Second Prospective reflect input data from several different sources. In some cases, the analysis retained input data already included in version 2.1.9 of IPM (i.e., the version of IPM used to develop EPA's 2004 EPA Base Case), but for several key variables the inputs in version 2.1.9 of the model were replaced with more recent data. With these updated data, the version of IPM used for the Second Prospective may reflect recent trends in the electricity market more accurately than IPM version 2.1.9.

To construct the IPM model plants representing all existing and planned electric generating units for the 2010/2020 emissions analyses, the National Electric Energy System (NEEDS) 2004 database was used as the primary source of data, consistent with version 2.1.9 of IPM. The NEEDS 2004 database contains the following unit-level information: location (model region, state, and county); capacity; plant type; pollution control equipment installed for SO_2, NO_x, and particulate matter; boiler configurations; mercury emission modification factors (EMF), and SO_2 and NO_x emission rates. Exhibits 4-2 and 4-3 summarize the sources of information EPA used to develop the NEEDS 2004 data for existing and planned/committed units, respectively.

EXHIBIT 4-2. DATA SOURCES FOR EXISTING UNITS IN NEEDS 2004

Data Source	Description
DOE's Form EIA-860a	DOE's Form EIA-860a is an annual survey of utility power plants at the generator level. It contains data such as summer, winter and nameplate capacity, location (state and county), status, prime mover, primary energy source, in-service year, and a plant-level cogenerator flag.
DOE's Form EIA-767	DOE's Form EIA-767 is an annual survey, "Steam-Electric Plant Operation and Design Report", that contains data for utility nuclear and fossil fuel steam boilers such as fuel quantity and quality; boiler identification, location, status, and design information; and postcombustion NO_x control, FGD scrubber and particulate collector device information. Note that boilers in plants with less than 10 MW do not report all data elements. The relationship between boilers and generators is also provided, along with generator-level generation and nameplate capacity. Note that boilers and generators are not necessarily in a one-to-one correspondence.
NERC Electricity Supply and Demand (ES&D) database	The NERC ES&D is released annually. It contains generator-level information such as summer, winter and nameplate capacity, state, NERC region and sub-region, status, primary fuel and on-line year.
DOE's Annual Energy Outlook (AEO) 2004	The Annual Energy Outlook (AEO 2004) presents midterm forecasts of energy supply, demand and prices through 2025 prepared by the Energy Information Administration (EIA). The projects are based on results from EIA's National Energy Modeling System (NEMS). Information from AEO 2004, such as heat rate, RPS inducing renewable builds, etc. is adopted in NEEDS 2.1.9.
Platt's NewGen Database	NewGen delivers a comprehensive, detailed assessment of the current status of proposed power plants in the United States. NewGen information is continually updated by Platts' research staff and NEEDS 2.1.9 used the information updated in December 2003.
EPA's Emission Tracking System (ETS)	The Emission Tracking System (ETS) database is updated quarterly. It contains boiler-level information such as primary fuel, heat input, SO_2 and NO_x controls, and SO_2, NO_x and CO_2 emissions. NEEDS 2.1.9 used Quarters 3 & 4 of 2002 and Quarters 1 & 2 of 2003 for developing emission rates and used Quarter 4 2003 for developing post-combustion control information.

EXHIBIT 4-3. DATA SOURCES FOR PLANNED UNITS IN NEEDS 2004

Type	Capacity (MW)	Years Described	Data Source
Renewables/Non-conventional			
Biomass	293	2004-2009	AEO 2004 Inventory of Planned/Committed Units
Geothermal	723	2004-2015	
Landfill Gas	137	2004-2009	
Solar	156	2004-2013	
Other	50	2007-2009	
Wind	1,280	2004-2015	
Fossil/Conventional			
Coal Steam	1,948	2004-2008	Platts RDI NewGen Database
Combined Cycle	36,622	2004-2007	
Turbine	6,065	2004-2007	
Fossil Waste	523	2004-2007	
TOTAL	47,797		

In addition to the unit data included in IPM version 2.1.9, the IPM analyses conducted for the Second Prospective also use the same natural gas supply curves from this version of the model. As indicated above, the natural gas supply curves from IPM v2.1.9 are based on the recommendations of a peer review panel convened in October 2003 and detailed supply and demand data obtained from the NPC's 2003 Natural Gas Study. Based on these data, EPA developed natural gas supply curves specific to each year in the IPM planning horizon. Although more up-to-date supply curves may better reflect recent changes in natural gas prices, a sensitivity analysis conducted by EPA suggests that IPM's results are not highly sensitive to natural gas prices.[36] Therefore, updating the model with more recent supply curves is unlikely to have a significant impact on the EGU emissions results for the Second Prospective.

The coal supply curves included in the 2010/2020 IPM analysis for the Second Prospective are similar to those included in version 2.1.9 of IPM. These supply functions reflect the estimated size of the coal resource base, supply costs, and coal supply productivity. For the Second Prospective, the resource base and coal supply cost estimates included in version 2.1.9 of IPM were retained but the coal supply productivity data in the model were updated with estimates from the Department of Energy's *Annual Energy Outlook 2005* (AEO 2005).

In addition to replacing the coal mine productivity data in IPM with more recent data from AEO 2005, AEO 2005 data were used for several other key model inputs. This application of AEO 2005 data is consistent with the emissions analyses for other source categories, which also rely heavily on AEO 2005 data. The AEO 2005 data incorporated into IPM for the Second Prospective include the following:

- Electricity demand;
- Oil price projections;

[36] U.S. EPA, "Multi-pollutant Analysis: Natural Gas Price Sensitivity, " April 2006, http://www.epa.gov/airmarkets/mp/.

- Life extension costs for fossil and nuclear power plants;
- Costs and technical specifications for new units (conventional and renewable);
- Nuclear availability and uprates,[37] and
- International energy imports.

In most cases AEO 2005 data were input directly into IPM; however, the AEO 2005 projections of electricity demand were adjusted to reflect EPA assumptions regarding future improvements in energy efficiency. These adjustments to AEO projections have been applied in other recent EPA analyses of the EGU sector to reflect EPA views on the future success of programs such as Energy Star. AEO 2005 projects annual electricity demand growth of 1.86 percent through 2025. Based on this estimate and the Agency's assumptions with respect to energy efficiency, EPA estimates annual growth of 1.63 percent.[38]

IPM ANALYSES FOR 2001

As indicated in Chapter 1 of this report, the Second Prospective study estimates the impacts of the Amendments for the years 2000, 2010, and 2020. The previous section outlines the approach for estimating emissions impacts at electric utilities for the 2010 and 2020 target years. For 2000, EGU emissions impacts in 2001 are used as a proxy for impacts in 2000. Due to resource constraints and model limitations, the Project Team adapted the 2001 validation analysis examined above instead of developing a new analysis for the year 2000.

In this section, we describe the Project Team's application of IPM for the 2001 *with-CAAA* and *without-CAAA* IPM analyses. These analyses were designed differently than the 2010 and 2020 model runs because they require IPM to estimate emissions retrospectively. As a forward-looking model, IPM was not designed for such an analysis and requires a number of adjustments to ensure that its results for a 2001 model run reflect historical conditions.

REGULATORY SCENARIOS FOR THE 2001 IPM ANALYSIS

The *with-CAAA* scenario for the 2001 IPM analysis is the same as the *with-CAAA* scenario for the 2010 and 2020 analyses except that the 2001 scenario does not reflect any regulations or NSR settlements not yet in effect in 2001. Therefore, the Clean Air Interstate Rule, Clean Air Mercury Rule, and other regulations promulgated after 2001 are not included in the *with-CAAA* scenario for 2001. The *without-CAAA* scenario for 2001 is exactly the same as the corresponding scenarios for 2010 and

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[37] An uprate is the process of increasing the maximum power level at which a nuclear plant can legally operate. U.S. Nuclear Regulatory Commission, "Uprates,"

http://www.nrc.gov/reactors/operating/licensing/power-uprates.html#definition, accessed June 20, 2006.

[38] Personal communication with John Laitner, U.S. EPA Office of Atmospheric Programs, August 17, 2005.

2020 in that regulatory controls on EGU emissions are frozen at 1990 levels of scope and stringency.

INPUT DATA AND CONFIGURATION OF IPM FOR THE 2001 EMISSIONS ANALYSIS

Similar to the IPM analyses conducted for 2010 and 2020, the analysis for 2001 is based on version 2.1.9 of IPM. For the 2001 analysis, the following data inputs were included in the model:

- IPM model units representing existing units were developed from the 2001 inventory of EGUs, as represented in NEEDS 2004.
- Electricity demand, peak load, and load shape were set to 2001 levels.[39] Electricity demand data from the North American Electric Reliability Council indicate that electricity demand in 2001 was approximately 1 percent lower than demand in 2000.[40]

Edited footnote → Electricity demand and peak load for 2001 as estimated in the North American Electric Reliability Council, Electricity Supply & Demand 2002 database were used. Load shape was estimated based on data from the Federal Energy Regulatory Commission Form 714 for 2001.

- Coal supply curves for the year 2000, as included in the EPA 2004 Base Case.
- Natural gas supply curves for 2003, as developed after the 2003 peer review of IPM's assumptions pertaining to natural gas.
- For the *with-CAAA* scenario, emissions are constrained to the values reported in EPA's 2001 compliance reports for Title IV SO_2 and OTR NO_x cap.[41] According to EPA data, EGU emissions of SO_2 and NO_x were approximately 5 percent and 8 percent lower, respectively, in 2001 than in 2000.[42]
- Environmental controls under the *with-CAAA* scenario are restricted to those reported in EPA's Emission Tracking System (ETS) in 2001, excluding NO_x controls added after September 2001 and all scrubbers built in 2001. NO_x controls installed after September were excluded because the Project Team assumed that controls installed at this time represent investments to limit emissions in 2002 and later years. Scrubbers constructed in 2001 were excluded because no data indicating the month or season of installation were readily available.

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[39] The Project Team used electricity demand and peak load for 2001 as estimated in the North American Electric Reliability Council, Electricity Supply & Demand 2002 database. For load shape, the Project Team used data from the Federal Energy Regulatory Commission Form 714 for 2001.

[40] North American Electric Reliability Council, O*p cit*.

[41] Emissions of SO_2 and NO_x are constrained based on values in U.S. EPA, "EPA Acid Rain Program 2001 Progress Report," November 2002 and U.S. EPA, "2001 OTC NO_x Budget Program Compliance Report," March 26, 2002.

[42] U.S. EPA, "EPA Acid Rain Program 2001 Progress Report," November 2002.

With these inputs included in the model for the 2001 analysis, IPM was configured to make endogenous dispatch decisions but was restricted from making any investments in new control technologies or generating capacity. This ensured that the capital reflected in the model's emissions estimates was consistent with the EGU capital stock in place in 2001.

RESULTS

In this section we present the results of the EGU emissions analyses conducted for the Second Prospective. These results include emissions under the *with-CAAA* and *without-CAAA* scenarios; the projected generation and capacity mix (by fuel type) under each scenario; estimated allowance prices for SO_2, NO_x, and mercury; and fuel and electricity prices under each scenario. We also compare the results for the 2001 *with-CAAA* scenario with ETS-CEM data collected for 2001.

EMISSIONS

Exhibits 4-4 and 4-5 summarize our EGU emissions estimates for VOC, NO_x, CO, SO_2, PM_{10}, $PM_{2.5}$, Hg, and NH_3 for 1990, 2001, 2010, and 2020. Under the *without-CAAA* scenario, NO_x and SO_2 emissions grow significantly between 1990 and 2010, but emissions of both pollutants remain relatively flat during the 2010-2020 period. *Without-CAAA* emissions of NO_x from electric utilities increase by approximately 4 percent during this period while SO_2 emissions fall by approximately 1 percent. This reflects the confluence of a number of factors during the 2010-2020 period, including increased reliance on coal-fired plants in compliance with the NSPS and a change in the relative prices of different types of coal. Based on AEO 2005 projections of coal mine productivity, IPM estimates that the price of low-sulfur sub-bituminous coal will decline relative to other types of coal during this period.

Under the *with-CAAA* scenario, EGU emissions of both NO_x and SO_2 decline significantly between 1990 and 2020. As indicated in Exhibit 4-4, emissions of NO_x from utilities fell from 6.4 million tons in 1990 to 4.5 million tons in 2001. We estimate that emissions will continue falling to 2.4 million tons in 2010 and 2.0 million tons in 2020. Relative to the *without-CAAA* scenario, this represents a 71 percent reduction in EGU NO_x emissions for 2010 and a 77 percent reduction for 2020. Similarly, SO_2 emissions from utilities fell from 15.8 million tons in 1990 to 10.8 million tons in 2001 under the *with-CAAA* scenario and are expected to decline further to 6.4 million tons in 2010 and 4.3 million tons in 2020. For 2001 this represents a 40 percent reduction in SO_2 emissions relative to the *without-CAAA* scenario and a 77 percent reduction for 2020.

In addition to NO_x and SO_2, the Amendments also lead to reduced emissions of directly-emitted PM_{10} and $PM_{2.5}$ from electric utilities, although these reductions are not as significant as those for NO_x and SO_2. For 2010, we estimate that direct $PM_{2.5}$ and PM_{10} emissions will be 25 percent and 21 percent less, respectively, under the *with-CAAA* scenario than under the *without-CAAA* scenario. By 2020 these differences will change to 34 percent and 29 percent for $PM_{2.5}$ and PM_{10} respectively.

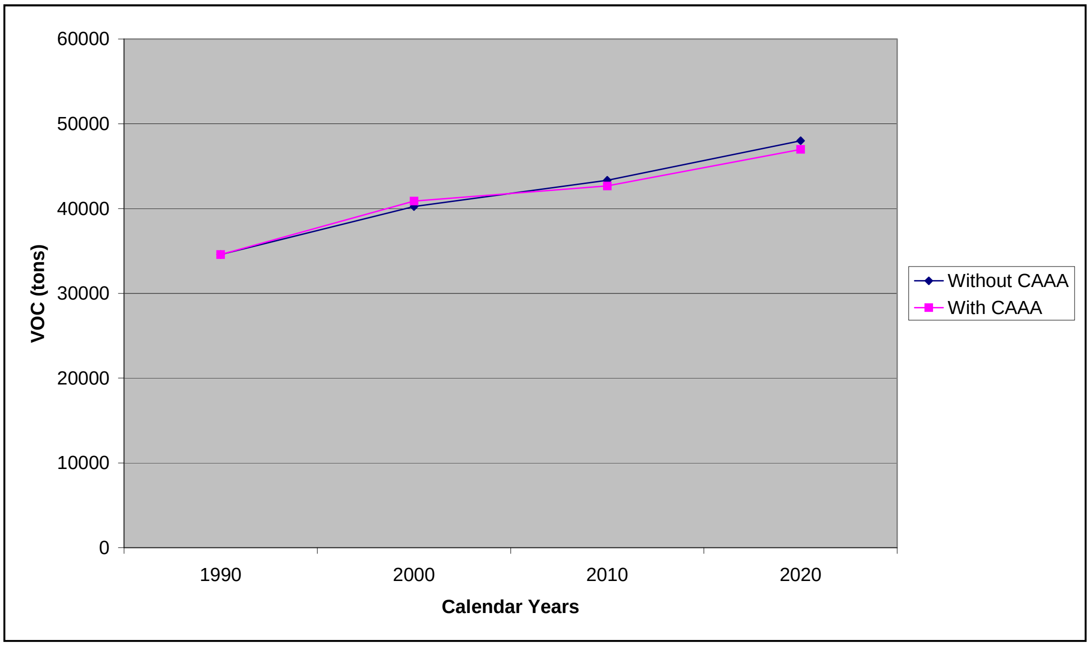
For most of the other pollutants included in Exhibit 4-4, emissions from utilities increase under both the *with-CAAA* and *without-CAAA* scenarios. In contrast, estimated EGU emissions of ammonia appear to fall significantly between 2001 and 2020 under both scenarios. These results are artificially low because EPA's post-processing methodology for version 2.1.9 of IPM does not include ammonia emission factors for combined cycle units or turbines, which were not available at the time this methodology was developed. Between 2001 and 2020, utilities are expected to replace several boiler units with combined cycle or turbine systems. Because the post-processing methodology does not capture ammonia emissions from these sources, total ammonia emissions appear to decline under both the *with-CAAA* and *without-CAAA* scenarios. Although these estimates do not accurately reflect EGU ammonia emissions, the results in Exhibit 4-4 suggest that EGU ammonia emissions are relatively insignificant relative to emissions from other sources. For example, we estimate that non-EGU point sources will emit approximately 1.1 million tons of ammonia in 2010 under the *with-CAAA* scenario, compared to just 822 tons for electric utilities.

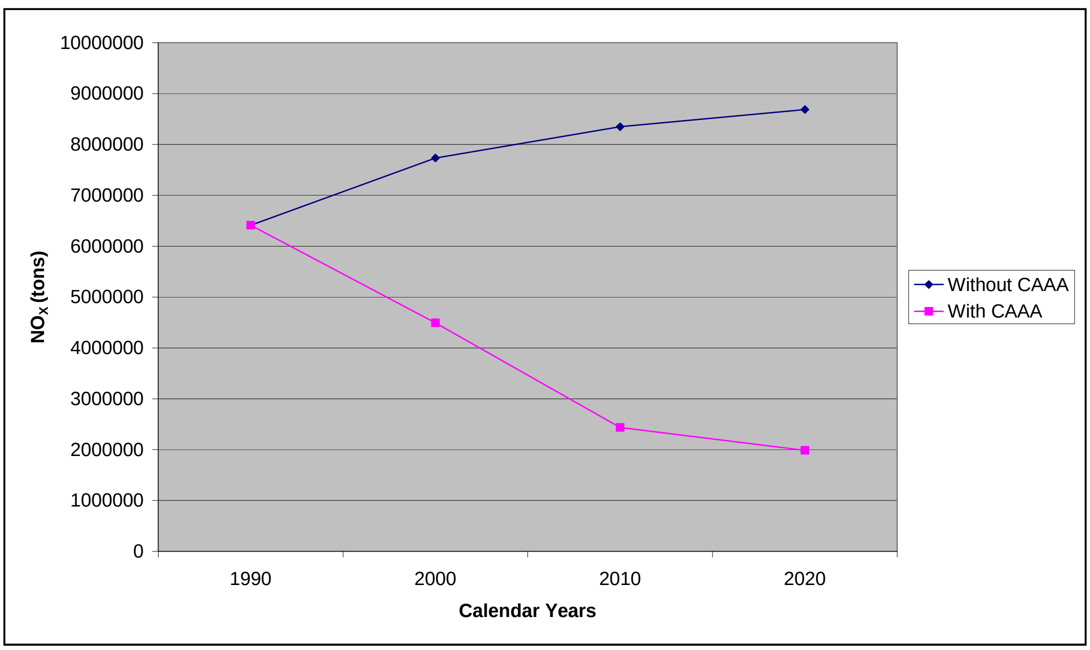
The results in Exhibit 4-4 also suggest that *with-CAAA* emissions of carbon monoxide (CO) exceed CO emissions under the *with-CAAA* scenario. This reflects the shift in generation from coal-fueled units to natural gas systems under the *with-CAAA* scenario. Because natural gas units emit more CO per unit of heat input than coal units, CO emissions are higher under the *with-CAAA* scenario. Similarly, *with-CAAA* emissions of volatile organic compounds (VOCs) exceed *without-CAAA* emissions in 2001 because natural gas units emit more VOCs per unit of heat input than coal-fueled systems.

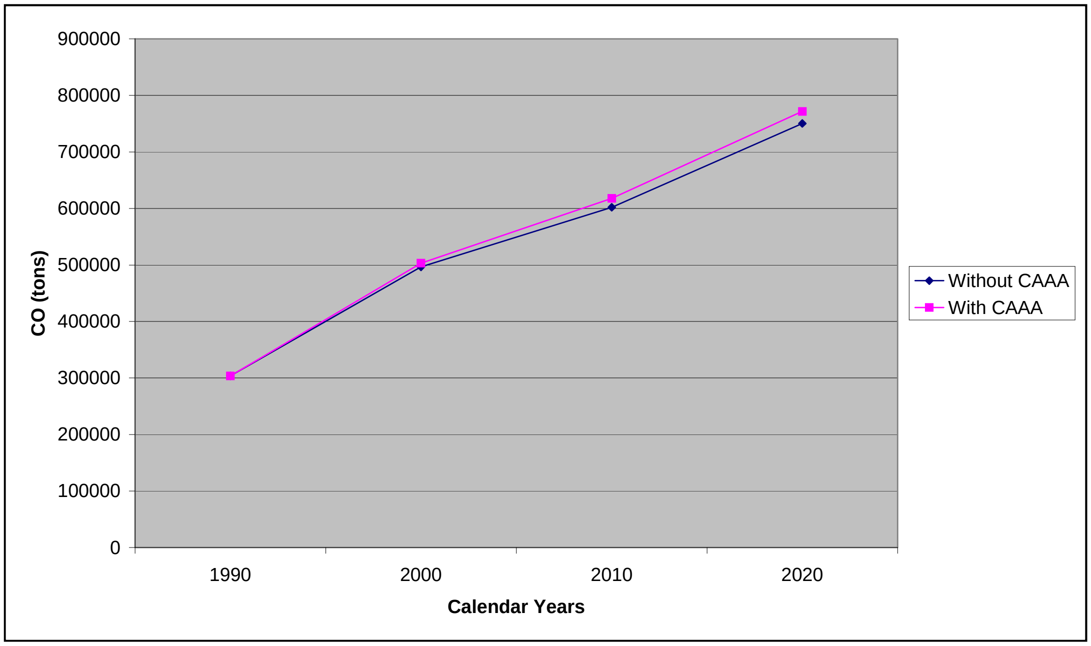
EXHIBIT 4-4. EGU EMISSIONS TOTALS BY POLLUTANT (TONS)

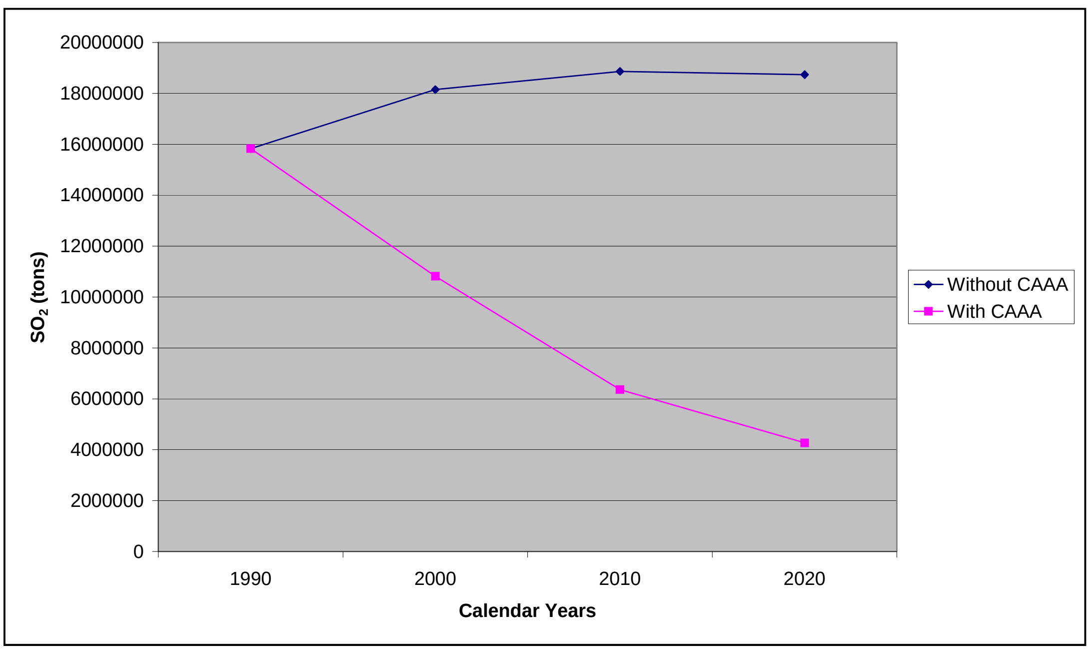
Pollutant	Fuel Type	1990	2001 *without-CAAA*	2001 *with-CAAA*	2010 *without-CAAA*	2010 *with-CAAA*	2020 *without-CAAA*	2020 *with-CAAA*
VOC	Coal	27,127	32,120	32,683	35,631	34,950	37,354	35,911
	Gas	2,166	7,845	8,064	7,547	7,623	10,556	10,989
	Other	5,266	273	135	155	91	91	91
	Total	34,558	40,238	40,882	43,333	42,664	48,001	46,992
NO_x	Coal	5,639,083	7,381,429	4,231,399	8,037,163	2,270,314	8,245,052	1,805,780
	Gas	565,385	345,587	253,973	296,971	151,989	426,196	165,714
	Other	206,065	6,984	8,609	15,348	14,916	14,969	14,969
	Total	6,410,533	7,734,001	4,493,981	8,349,482	2,437,219	8,686,216	1,986,463
CO	Coal	234,285	297,781	300,499	332,292	340,308	349,125	351,638
	Gas	50,623	196,788	201,852	268,556	276,772	400,632	419,235
	Other	18,805	1,861	955	1,200	779	782	782
	Total	303,713	496,430	503,306	602,048	617,860	750,539	771,654
SO_2	Coal	15,218,684	18,095,299	10,797,563	18,853,888	6,365,458	18,738,860	4,270,125
	Gas	757	0	0	0	0	0	0
	Other	612,261	51,360	21,836	13,644	0	0	0
	Total	15,831,702	18,146,659	10,819,399	18,867,532	6,365,458	18,738,860	4,270,125
Primary PM_{10}	Coal	506,247	734,401	711,370	812,049	635,036	863,743	602,775
	Gas	4,758	16,455	16,854	21,845	22,490	32,418	33,907
	Other	19,657	840	495	761	625	630	630
	Total	530,663	751,696	728,719	834,655	658,151	896,790	637,311
Primary $PM_{2.5}$	Coal	337,857	617,037	593,325	681,929	506,137	729,368	472,065
	Gas	3,924	16,455	16,854	21,845	22,490	32,418	33,907
	Other	15,893	795	459	670	536	540	540
	Total	357,674	634,287	610,638	704,443	529,163	762,326	506,512
NH_3	Coal	Not estimated	285	289	316	310	329	317
	Gas	Not estimated	2,680	2,766	640	511	282	241
	Other	Not estimated	252	107	67	0	0	0
	Total	Not estimated	3,217	3,162	1,023	822	612	559

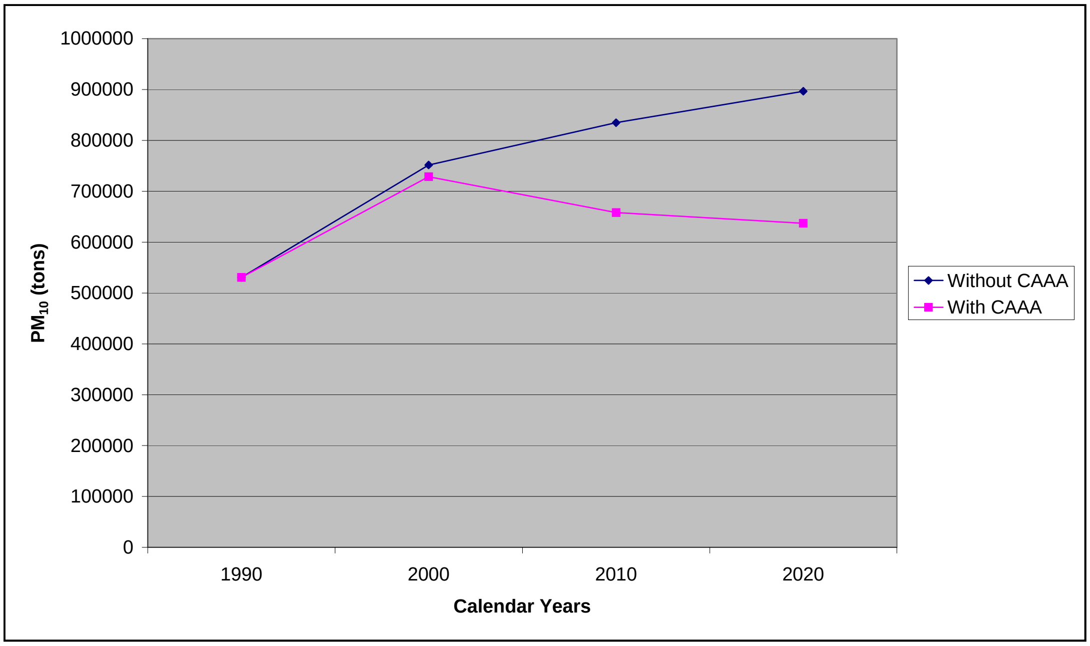
EXHIBIT 4-5. EGU EMISSIONS SUMMARIES UNDER THE *WITH-CAAA* AND *WITHOUT-CAAA* SCENARIOS, BY POLLUTANT






900000
800000
700000
600000
500000
400000
300000
200000
100000
0
CO (tons)
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


20000000
18000000
16000000
14000000
12000000
10000000
8000000
6000000
4000000
2000000
0
SO_2 (tons)
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


1000000
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200000
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0
PM10 (tons)
1990
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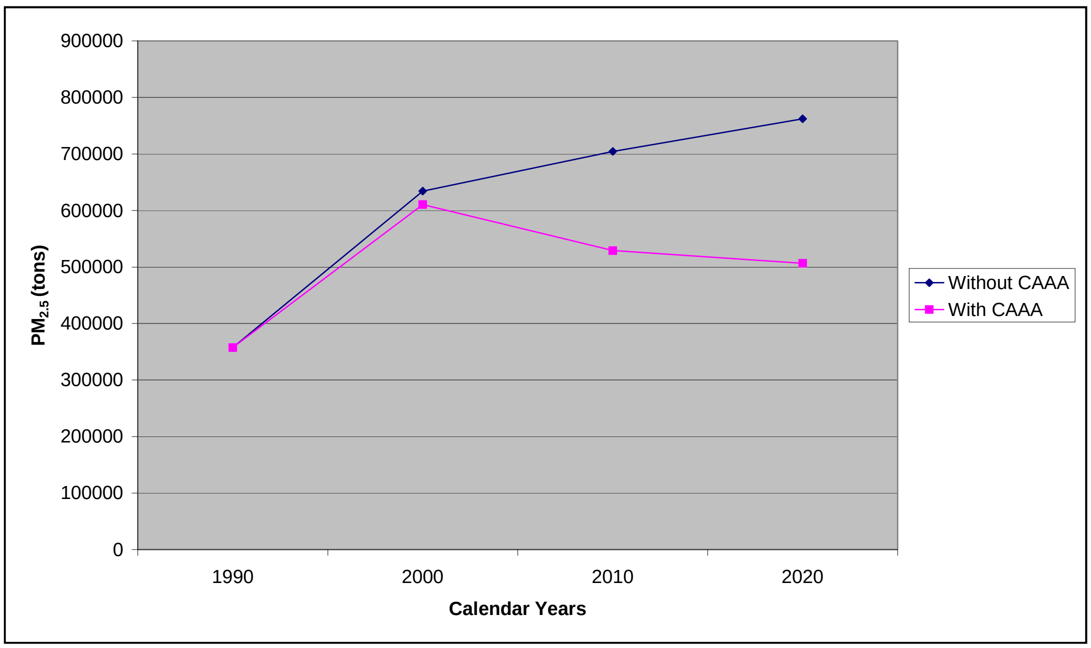
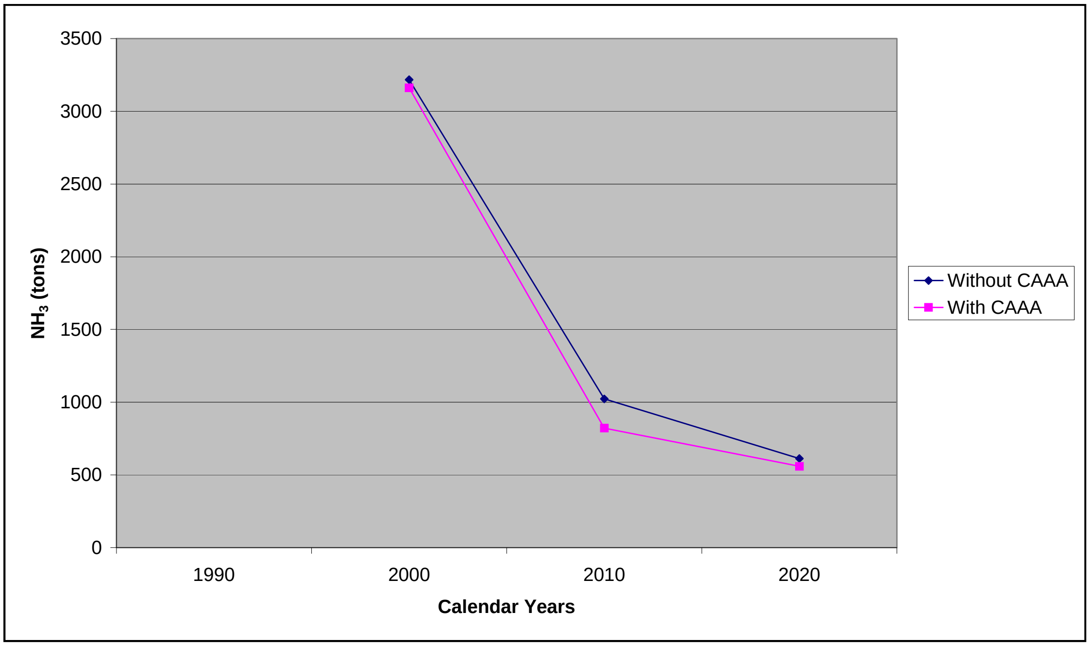
2010
2020
Calendar Years
Without CAAA
With CAAA


900000
800000
700000
600000
500000
400000
300000
200000
100000
0
PM2.5 (tons)
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


3500
3000
2500
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1000
500
0
NH_3 (tons)
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA

CHAPTER 5 | NONROAD ENGINES/VEHICLES

OVERVIEW OF APPROACH

We developed nonroad engine and nonroad vehicle emission estimates using EPA's Office of Transportation and Air Quality's (OTAQ) NONROAD2004 model. Nonroad equipment categories not included in NONROAD (e.g., refueling emissions) are discussed in Chapter 7, as nonpoint or area sources. The NONROAD2004 model was released by EPA in May 2004 (EPA, 2004a). This version of the model incorporates all Federal engine exhaust standards, and includes updates to the base year diesel engine populations.

The NONROAD model is an EPA peer-reviewed model that is used in developing both base year and forecast year emission estimates for most nonroad source categories. The model has been used in support of multiple EPA regulatory analyses, including the Clean Air Nonroad Diesel Rule and the Clean Air Interstate Rule. The NONROAD model incorporates data for numerous nonroad engine parameters to estimate both historical and forecast year emissions.

As described further below, the NONROAD model includes its own national equipment growth rates. These growth rates are not derived from AEO 2005 modeling, but from extrapolation of historical trends. We would have liked to have revised the NONROAD model's forecasting approach to incorporate *AEO 2005* fuel consumption projections, which would have involved modifying the NONROAD national equipment growth rates. While it is feasible to alter the national growth rates, to do so might have created new inconsistencies internal to the NONROAD model, because the equipment growth rates in NONROAD were derived from the same survey source as the disaggregated equipment category scrappage/retirement and usage rates that are also part of NONROAD input data. Altering only the growth rates might make them inconsistent with the retirement rates, which might then have created inconsistencies with AEO fuel consumption projections. Therefore, the national growth rates used here are consistent with the national NONROAD model data/assumptions that have been used in multiple EPA regulatory analyses. The Project Team conducted a consistency check to evaluate the impact of this assumption, comparing aggregate fuel consumption projections implicit in the NONROAD modeling with fuel consumption projections for this sector in *AEO 2005*. The results are reported at the end of this chapter - while we found several inconsistencies, we believe the more detailed NONROAD input data prove a better basis for assessing the benefits of controls in this source category.

We did revise the model's input assumptions, however, to address an acknowledged model limitation related to the regional disaggregation of growth rates. While the national growth rates from NONROAD were retained, the regionalization of the national rates was based on *AEO 2005* regional activity allocation factors for the present study. The overall approach for this sector therefore involved three steps: 1) revising existing model inputs to better reflect region-specific growth rates, consistent with the *AEO 2005* results used elsewhere in this study; 2) preparing State and county-specific input files to model local fuel programs for the *with-CAAA* scenario runs; and 3) modifying fleet emission rate inputs to remove the effect of CAAA-related standards for the *without-CAAA* runs. The remainder of this chapter describes the process we used to complete these three steps, presents summary results for the category, and reports on two sensitivity analyses we conducted to evaluate particular areas of concern raised during the Council and AQMS reviews of the 2003 analytical plan.

GROWTH PROJECTIONS

For most equipment types, NONROAD utilizes historical engine population estimates up through 1998 from a proprietary database developed by Power Systems Research (PSR). This database contains detailed information about each engine family sold in the United States, and provided EPA NONROAD model developers with data for estimating historical engine populations by market sector (e.g., 2-stroke lawn and garden equipment), application type (e.g., chain saws), fuel type (e.g., gasoline), horsepower (hp) range (e.g., 3 to 6 hp); and vintage (e.g., model year 1990 engines).[43] To develop projections of engine populations, EPA applies growth and retirement rate assumptions to the detailed engine population estimates for the final year of historical data. For most source categories, the NONROAD projection growth rates reflect a straight-line projection of the growth in national engine population estimates developed by PSR for the period 1989-1996. NONROAD retirement assumptions reflect year-specific scrappage rates derived from median engine life assumptions that differ by engine application and hp range. Therefore, post-1998 year NONROAD engine populations (and emissions) are generally estimated in the model by applying an internally consistent set of historical/forecast model data/assumptions.[44]

EPA has acknowledged that "…the current national growth factors used in the NONROAD model do not accurately portray nonroad equipment/emissions growth at the regional or State levels" (EPA, 2004e). To account for expected differences in regional growth rates, and to provide consistency with the projection basis used for other emitting sectors, the Project Team incorporated regional growth projections into NONROAD. We specifically developed regional growth rates that reflect socioeconomic forecast data from the *Annual Energy Outlook 2005* (DOE, 2005), normalized to the NONROAD model national growth rates. The following describes how we computed these regional growth rates.

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[43] The vintage information is used to account for emission rates that differ for each model year engine.

[44] Emissions are computed using the engine population data, and assumptions as to load factors (average percentage of maximum rated horsepower at which engine is operated), number of operating hours per year, brake-specific fuel consumption (gallons/hp-hour), and emission rates (e.g., pounds of pollutant per gallon of fuel consumed).

The AEO growth indicators used for making the regional adjustments were selected to match as closely as possible with the surrogate indicator used in NONROAD to make allocations of equipment growth to individual counties. Exhibit 5-1 displays the NONROAD model county allocation surrogates and the *AEO 2005* indicators used to forecast/back-cast the base year county equipment populations for each year. For several categories, the AEO projections for the most representative surrogate indicator were only available at a national level (e.g., Wholesale Trade data for light commercial equipment). As shown in Exhibit 5-1, in those cases where regional growth rates were not available from the *AEO 2005* data, we used regional population projections.

The national NONROAD growth file ("NATION.GRW") was revised to incorporate first regional-level, and then by extension State-level growth rates using the following five steps:

(1) *Compute growth factors representing regional and national growth for each AEO 2005 surrogate indicator*. These growth factors were calculated by dividing the regional/national data for each forecast/back-cast year by the regional/national data for the base year.

(2) *Compile the national growth factors by equipment category/fuel type from the NATION.GRW file*. These growth factors were computed by dividing the national data for each forecast/back-cast year by the national data for the base year of 2000. In cases where growth data are not reported in the NATION.GRW file for a year of interest, the data were estimated by interpolating between the values for the two closest years (e.g., 2020 values were estimated from 2015 and 2025 values).

EXHIBIT 5-1. AEO REGIONAL SURROGATE INDICATORS USED TO ADJUST NONROAD GROWTH RATES

NONROAD Equipment Category	NONROAD County Allocation Surrogate	AEO 2005 Growth Surrogate[1]
Lawn and Garden Residential	Number of single and double (duplex) family housing units from 1990 Census grown to 1997 using 1990-1997 change in county human population from U.S. Census Bureau.	Population
Lawn and Garden Commercial	Number of employees in landscape and horticultural services, County Business Patterns (CBP), SIC code 078.	Population
Residential Snowblowers	Same as residential lawn and garden, but allocation factors for counties with snowfall less than 15 inches set to zero.	Population
Commercial Snowblowers	Same as commercial lawn and garden, but allocation factors for counties with snowfall less than 15 inches set to zero.	Population
Construction	Categories (e.g., housing, commercial buildings, public works construction) of F.W. Dodge construction dollar value data weighted by 1998 Environ survey of construction equipment activity in Houston, TX and then totaled.	MFGO35 Construction (NAICS 23)

NONROAD Equipment Category	NONROAD County Allocation Surrogate	AEO 2005 Growth Surrogate[1]
Agricultural	Harvested cropland (U.S. Census Bureau, *USA Counties* database).	MFGO30 Crop Production (NAICS 111)
Recreational Marine	Water surface area with different operating limits from shore for personal watercraft, outboards, and inboards.	Population
Recreational Land-Based (except snowmobiles and golf carts)	Number of camps and recreational vehicle park establishments (CBP SIC 7030).	Population
Snowmobiles	Snowfall limit of 40 inches and inverse human population. Direct human population used for Alaska.	Population
Golf Carts	Number of public golf courses (CBP SIC 7992).	Population
Aircraft Ground Support Equipment	Number of employees in Air Transportation (CBP SIC 45)	Population
Light Commercial	Number of wholesale establishments (CBP SIC 50).	Population
Industrial (excluding AC/Refrigeration Equipment)	Number of employees in manufacturing (CBP SIC 20).	Total Manufacturing Output (NAICS 31-33)
AC/Refrigeration Equipment	Human population.	Population
Logging	Number of employees in logging (CBP SIC 2410).	MFGO31 Other Ag, Forestry, Fishing & Hunting (NAICS 112-115)
Oil Field Equipment	Number of employees engaged in oil and gas extraction (CBP SIC 1300).	Oil production[1]
Railroad Maintenance Equipment	Human population.	Population
Underground Mining Equipment	Number of employees in coal mining (CBP SIC 1200).	MFGO32 Coal Mining (NAICS 2121)

NOTE:
[1] Population represents EIA's National Energy Modeling System regional population projections.
[2] Compiled from Department of Energy's *Annual Energy Outlook 2005* (forecast data) and *Petroleum Supply Annual* (historical data).

(3) *Normalize the regional-level growth factors computed in step (1) to reflect the national growth rates reported in the NATION.GRW file*. This task was accomplished by multiplying the regional-level growth factors by the ratio of the national growth factor calculated from the NATION.GRW data from step (2) to the national growth factor calculated from the *AEO 2005* data from step (1)

(4) *Assign normalized regional growth factors to each State, and incorporate State-level growth factor data into the NATION.GRW file*. EPA OTAQ provided a revised NONROAD model test version executable that allows incorporation of up to 6,000 records per indicator code in the /GROWTH/ packet portion of the NATION.GRW file (Harvey, 2005).

(5) *Revise the crosswalk between NONROAD growth indicators and SCCs to reflect the use of regional growth indicators*.

After testing the updated NATION.GRW file to ensure it was producing the expected results, NONROAD model runs were conducted for each scenario year using this updated file.

CONTROL SCENARIO ASSUMPTIONS

This section describes the adjustments made to the NONROAD model inputs and/or results to accurately model: (a) 1990; (b) *without-CAAA* scenario for the years 2000, 2010, and 2020; and (c) *with-CAAA* scenario for the years 2000, 2010, and 2020.

Before conducting the modeling for these scenarios, however, appropriate temperature and fuel data inputs were compiled for each of the years of interest (1990, 2000, 2010 and 2020). Seasonal, State, or county-specific NONROAD model option files were prepared to generate nationwide emissions for each appropriate scenario. The NONROAD model uses ASCII format input files (termed *option* files) that specify the parameters for a specific model run, including ambient temperature and fuel characteristics for the modeled geographic area (e.g., State or county) and time period (e.g., summer season during the year 2000). 1990 and 2000 temperature input values for the *without-CAAA* model runs were based on Statewide average temperatures compiled for these specific years (EPA, 2004b). 2010 and 2020 temperature input values were based on a 30-year historical trend in Statewide average temperature.

The 1990 Statewide average seasonal RVP values were compiled and used as input values for the 2000, 2010, and 2020 model runs (EPA, 2004b). Several counties in California, Louisiana and New York had Stage II refueling programs established by 1990, so evaporative hydrocarbon reductions resulting from these programs were modeled for all *without-CAAA* runs. No oxygenated fuel programs were in place in 1990.

Using these option files, the Project team performed NONROAD model runs to generate seasonal emissions for each inventory year. Seasonal emissions outputs were summed to develop annual emission estimates at the county and SCC level for each scenario year.

WITHOUT-CAAA SCENARIO

For modeling a *without-CAAA* scenario for all years, the NONROAD model technology file (TECH.DAT) was revised to remove the effect of recent (since 1990) Federal nonroad control programs. A base technology with a sales fraction of 1 is reported for each equipment category or application for years prior to standard implementation (specified as year "1900"). The sales fraction input can be thought of as the market penetration for a given year for a particular emissions control technology. This fraction changes to account for sales of engines equipped with technologies needed to meet a specific standard for each implementation year. To ensure that the model applies emission rates corresponding to the "base" technology type for all *without-CAAA* runs, sales fractions for all other years besides "1900" were removed from the TECH.DAT file (i.e., they were set to 0 market penetration). The one exception to this was the T0 technology type for diesel engines. This technology type, which applies to engines sold in 1988 and after, was retained in the TECH.DAT files since this occurred prior to the CAAA, and was a result of the "spillover" of highway diesel control technology.

WITH-CAAA SCENARIO

Base-year fuel inputs were prepared to reflect seasonal Statewide average gasoline RVP, as well as county-specific inputs where local areas have program inputs that vary from Statewide defaults (e.g., RFG, Stage II, and oxygenated fuel programs). These inputs were derived from 2000 monthly fuel data compiled for the onroad mobile 1999 NEI (EPA, 2004b). Reid vapor pressure, Stage II control, and percent oxygen values for 2000 were assumed for 2010 and 2020 modeling runs.

Year-specific values for the nonroad diesel and gasoline fuel sulfur levels were also incorporated as shown in Exhibit 5-2. These are consistent with the fuel sulfur values used in support of EPA final rulemakings for the Tier 2 and gasoline sulfur standards (65 FR 6698, 2000) and the Clean Air Nonroad Diesel Rule (EPA, 2004c). Note that EPA estimates diesel land-based nonroad equipment to have lower diesel fuel sulfur levels than comparable diesel recreational marine vessels. NONROAD2004 requires multiple sets of runs to reflect more than one diesel fuel sulfur level. As such, SO_2 emissions output for diesel recreational marine were multiplied by the adjustment factors listed in Exhibit 5-2. The adjustment factors provide a ready means of modeling the differential fuel requirements for recreational marine versus land-based fuels. These adjustment factors were calculated based on the ratio of the recreational marine sulfur level to the land-based sulfur level, consistent with the assumption that SO_2 emissions are proportioned to fuel sulfur content. Increases in direct PM_{10} and $PM_{2.5}$ emissions for recreational marine would also result from higher fuel sulfur levels, but the Project Team determined that these increases would be relatively small and therefore no adjustments were made for emissions of these pollutants in this category.

Federal emission standards not incorporated by NONROAD2004 include permeation and evaporative emission standards for gasoline recreational and large S-I engines, respectively. Emission reductions due to the large S-I standard were developed to apply to the affected SCCs as a post-processing adjustment. Note that evaporative standards for recreational equipment only reduce permeation evaporative emissions, which are not modeled by NONROAD2004.[45] Therefore, recreational equipment permeation emission standards were not modeled.

For the large S-I evaporative standard, base and control case future year inventories compiled by EPA were used to calculate emission reductions for 2010 and 2020 (EPA, 2002). These emission reductions vary by evaporative component, but for this analysis emissions were summed across all evaporative components to estimate emission reductions. Large S-I evaporative VOC emission reductions were estimated to be 59.7 percent in 2010, and 82 percent in 2020.

Two rule penetration adjustments were applied to account for the fraction of the SCC-level emissions that are affected by the rule. Since the rule only affects S-I engines greater than 25 horsepower, the first adjustment was developed to estimate that fraction of the activity associated with these larger engines. The adjustment was based on 2002 national gasoline consumption results by horsepower and equipment category from NONROAD2004. We assumed the same rule penetration value for each projection year and for all applications within a category. Although rule penetration is likely to vary by year and application, we currently have no basis for estimating that variation. Exhibit 5-3 summarizes the horsepower-related rule penetration values by equipment category.

[45] The 2005 version of the NONROAD model does incorporate permeation evaporative emissions from recreational equipment. However, this version of the model was not available at the time that analytic decisions for this report were made.

EXHIBIT 5-2. FUEL SULFUR LEVELS (WEIGHT %) FOR SECTION 812 NONROAD MODEL RUNS

	1990	2000		2010		2020	
		without-CAAA	***with-CAAA***	***without-CAAA***	***with-CAAA***	***without-CAAA***	***with-CAAA***
Gas Sulfur %	0.0339	0.0339	0.0339	0.0339	0.003	0.0339	0.003
CNG/LPG Sulfur %	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Diesel Sulfur % - Land Based	0.25	0.2284	0.2284	0.2284	0.017	0.2284	0.0011
Diesel Sulfur % - Rec Marine	0.264	0.264	0.264	0.264	0.0319	0.264	0.0055
Rec Marine SO_2 Adjustment[1]	*1.056*	*1.156*	*1.156*	*1.156*	*1.933*	*1.156*	*5.000*

NOTE: [1]Represents SO_2 emissions adjustments for diesel recreational marine SCCs 2282020005 and 2282020010.

EXHIBIT 5-3. HORSEPOWER RULE PENETRATION VALUES BY CATEGORY FOR LARGE S-I EVAPORATIVE STANDARDS

Fuel Type	Classification	Rule Penetration, %
Gasoline	Agricultural Equipment	40
	Airport Equipment	74
	Commercial Equipment	5
	Construction and Mining Equipment	14
	Industrial Equipment	59
	Commercial Lawn and Garden Equipment	7
	Railroad Equipment	4
	Recreational Equipment[1]	43
CNG	All Classifications	100
LPG	All Classifications	100

NOTE: [1]Applies to specialty vehicle carts only; other recreational equipment covered by recreational standards.

A second rule penetration adjustment by SCC was also developed to account for that fraction of the SCC-level emissions associated with evaporative VOC relative to the total VOC emissions (i.e., exhaust plus evaporative). These rule penetration values varied by year and SCC. These adjustments enable the emission reductions to be applied directly to the SCC-level VOC emissions output from the NONROAD model as a post-processing step. See Exhibit 5-4 for the 2010 and 2020 SCC-specific evaporative rule penetration values and final control factors.

The following equation shows an example of how overall adjusted emission reductions were estimated for 4-stroke industrial forklifts in 2020:

$$ER_{ADJ} = RP_{hp} \times RP_{evap} \times ER$$

where:

ER_{ADJ} = adjusted emission reduction accounting for rule penetration

RP_{hp} = rule penetration for affected horsepower fraction

RP_{evap} = rule penetration for evaporative fraction of total VOC emissions

ER = evaporative emission reduction for affected engines

$$ER_{ADJ} = 0.591 \times 0.567 \times 0.82$$

$$= 0.275$$

$$= 27.5 \text{ percent}$$

EXHIBIT 5-4. VOC EVAPORATIVE RULE PENETRATION AND FINAL CONTROL EFFECTIVENESS VALUES BY SCC FOR LARGE S-I VOC EVAPORATIVE STANDARDS IN 2010 AND 2020

SCC	Equipment	Classification	Engine Type	2010 Evaporative Rule Penetration	2010 Overall Control Efficiency (%)	2020 Evaporative Rule Penetration	2020 Overall Control Efficiency (%)
2260001060	Specialty Vehicles/Carts	Recreational Equipment	2 Stroke	0.326	8.3	0.338	11.8
2260002006	Tampers/Rammers	Construction and Mining Equipment	2 Stroke	0.025	0.2	0.025	0.3
2260002009	Plate Compactors	Construction and Mining Equipment	2 Stroke	0.058	0.5	0.058	0.6
2260002021	Paving Equipment	Construction and Mining Equipment	2 Stroke	0.052	0.4	0.052	0.6
2260002027	Signal Boards/Light Plants	Construction and Mining Equipment	2 Stroke	0.029	0.2	0.029	0.3
2260002039	Concrete/Industrial Saws	Construction and Mining Equipment	2 Stroke	0.013	0.1	0.014	0.2
2260002054	Crushing/Proc. Equipment	Construction and Mining Equipment	2 Stroke	0.033	0.3	0.033	0.4
2260003030	Sweepers/Scrubbers	Industrial Equipment	2 Stroke	0.082	2.9	0.082	4.0
2260003040	Other General Industrial Eqp	Industrial Equipment	2 Stroke	0.059	2.1	0.059	2.8
2260004016	Rotary Tillers < 6 HP	Lawn and Garden Equipment (Com)	2 Stroke	0.167	0.7	0.171	1.0
2260004021	Chain Saws < 6 HP	Lawn and Garden Equipment (Com)	2 Stroke	0.183	0.7	0.183	1.0
2260004026	Trimmers/Edgers/Brush Cutter	Lawn and Garden Equipment (Com)	2 Stroke	0.210	0.9	0.210	1.2
2260004031	Leafblowers/Vacuums	Lawn and Garden Equipment (Com)	2 Stroke	0.070	0.3	0.070	0.4
2260004036	Snowblowers	Lawn and Garden Equipment (Com)	2 Stroke	0.037	0.2	0.037	0.2
2260004071	Commercial Turf Equipment	Lawn and Garden Equipment (Com)	2 Stroke	0.045	0.2	0.045	0.3
2260005035	Sprayers	Agricultural Equipment	2 Stroke	0.120	2.8	0.120	3.9
2260005050	Hydro Power Units	Agricultural Equipment	2 Stroke	0.052	1.2	0.052	1.7
2260006005	Generator Sets	Commercial Equipment	2 Stroke	0.109	0.3	0.109	0.5
2260006010	Pumps	Commercial Equipment	2 Stroke	0.079	0.2	0.080	0.3
2260006015	Air Compressors	Commercial Equipment	2 Stroke	0.059	0.2	0.059	0.2
2265001060	Specialty Vehicles/Carts	Recreational Equipment	4 Stroke	0.241	6.1	0.221	7.7
2265002003	Pavers	Construction and Mining Equipment	4 Stroke	0.139	1.1	0.130	1.5
2265002006	Tampers/Rammers	Construction and Mining Equipment	4 Stroke	0.142	1.2	0.143	1.6
2265002009	Plate Compactors	Construction and Mining Equipment	4 Stroke	0.103	0.8	0.106	1.2
2265002015	Rollers	Construction and Mining Equipment	4 Stroke	0.113	0.9	0.110	1.2
2265002021	Paving Equipment	Construction and Mining Equipment	4 Stroke	0.162	1.3	0.163	1.8
2265002024	Surfacing Equipment	Construction and Mining Equipment	4 Stroke	0.105	0.9	0.104	1.2
2265002027	Signal Boards/Light Plants	Construction and Mining Equipment	4 Stroke	0.091	0.7	0.091	1.0
2265002030	Trenchers	Construction and Mining Equipment	4 Stroke	0.127	1.0	0.117	1.3
2265002033	Bore/Drill Rigs	Construction and Mining Equipment	4 Stroke	0.190	1.5	0.192	2.1
2265002039	Concrete/Industrial Saws	Construction and Mining Equipment	4 Stroke	0.091	0.7	0.090	1.0
2265002042	Cement & Mortar Mixers	Construction and Mining Equipment	4 Stroke	0.231	1.9	0.268	3.0
2265002045	Cranes	Construction and Mining Equipment	4 Stroke	0.331	2.7	0.407	4.5
2265002054	Crushing/Proc. Equipment	Construction and Mining Equipment	4 Stroke	0.131	1.1	0.125	1.4

SCC	Equipment	Classification	Engine Type	2010 Evaporative Rule Penetration	2010 Overall Control Efficiency (%)	2020 Evaporative Rule Penetration	2020 Overall Control Efficiency (%)
2265002057	Rough Terrain Forklifts	Construction and Mining Equipment	4 Stroke	0.358	2.9	0.573	6.4
2265002060	Rubber Tire Loaders	Construction and Mining Equipment	4 Stroke	0.365	3.0	0.633	7.1
2265002066	Tractors/Loaders/Backhoes	Construction and Mining Equipment	4 Stroke	0.095	0.8	0.094	1.0
2265002072	Skid Steer Loaders	Construction and Mining Equipment	4 Stroke	0.259	2.1	0.259	2.9
2265002078	Dumpers/Tenders	Construction and Mining Equipment	4 Stroke	0.254	2.1	0.278	3.1
2265002081	Other Construction Equipment	Construction and Mining Equipment	4 Stroke	0.370	3.0	0.517	5.8
2265003010	Aerial Lifts	Industrial Equipment	4 Stroke	0.300	10.6	0.319	15.4
2265003020	Forklifts	Industrial Equipment	4 Stroke	0.320	11.3	0.567	27.5
2265003030	Sweepers/Scrubbers	Industrial Equipment	4 Stroke	0.201	7.1	0.196	9.5
2265003040	Other General Industrial Eqp	Industrial Equipment	4 Stroke	0.112	3.9	0.109	5.3
2265003050	Other Material Handling Eqp	Industrial Equipment	4 Stroke	0.279	9.8	0.287	13.9
2265003060	AC\Refrigeration	Industrial Equipment	4 Stroke	0.108	3.8	0.108	5.2
2265003070	Terminal Tractors	Industrial Equipment	4 Stroke	0.387	13.6	0.559	27.1
2265004011	Lawn mowers	Lawn and Garden Equipment (Com)	4 Stroke	0.288	1.2	0.289	1.6
2265004016	Rotary Tillers < 6 HP	Lawn and Garden Equipment (Com)	4 Stroke	0.289	1.2	0.356	2.0
2265004026	Trimmers/Edgers/Brush Cutter	Lawn and Garden Equipment (Com)	4 Stroke	0.488	2.0	0.491	2.7
2265004031	Leafblowers/Vacuums	Lawn and Garden Equipment (Com)	4 Stroke	0.335	1.4	0.339	1.9
2265004036	Snowblowers	Lawn and Garden Equipment (Com)	4 Stroke	0.332	1.4	0.332	1.9
2265004041	Rear Engine Riding Mowers	Lawn and Garden Equipment (Com)	4 Stroke	0.171	0.7	0.171	1.0
2265004046	Front Mowers	Lawn and Garden Equipment (Com)	4 Stroke	0.209	0.9	0.227	1.3
2265004051	Shredders < 6 HP	Lawn and Garden Equipment (Com)	4 Stroke	0.273	1.1	0.362	2.0
2265004056	Lawn & Garden Tractors	Lawn and Garden Equipment (Com)	4 Stroke	0.153	0.6	0.154	0.9
2265004066	Chippers/Stump Grinders	Lawn and Garden Equipment (Com)	4 Stroke	0.177	0.7	0.176	1.0
2265004071	Commercial Turf Equipment	Lawn and Garden Equipment (Com)	4 Stroke	0.121	0.5	0.122	0.7
2265004076	Other Lawn & Garden Eqp.	Lawn and Garden Equipment (Com)	4 Stroke	0.267	1.1	0.356	2.0
2265005010	2-Wheel Tractors	Agricultural Equipment	4 Stroke	0.110	2.6	0.110	3.6
2265005015	Agricultural Tractors	Agricultural Equipment	4 Stroke	0.250	5.9	0.271	8.8
2265005020	Combines	Agricultural Equipment	4 Stroke	0.513	12.1	0.624	20.3
2265005025	Balers	Agricultural Equipment	4 Stroke	0.575	13.6	0.690	22.4
2265005030	Agricultural Mowers	Agricultural Equipment	4 Stroke	0.147	3.5	0.151	4.9
2265005035	Sprayers	Agricultural Equipment	4 Stroke	0.280	6.6	0.310	10.1
2265005040	Tillers > 6 HP	Agricultural Equipment	4 Stroke	0.269	6.3	0.224	7.3
2265005045	Swathers	Agricultural Equipment	4 Stroke	0.512	12.1	0.623	20.2
2265005050	Hydro Power Units	Agricultural Equipment	4 Stroke	0.118	2.8	0.117	3.8
2265005055	Other Agricultural Equipment	Agricultural Equipment	4 Stroke	0.347	8.2	0.386	12.5
2265005060	Irrigation Sets	Agricultural Equipment	4 Stroke	0.348	8.2	0.470	15.2

SCC	Equipment	Classification	Engine Type	2010 Evaporative Rule Penetration	2010 Overall Control Efficiency (%)	2020 Evaporative Rule Penetration	2020 Overall Control Efficiency (%)
2265006005	Generator Sets	Commercial Equipment	4 Stroke	0.239	0.7	0.246	1.0
2265006010	Pumps	Commercial Equipment	4 Stroke	0.199	0.6	0.197	0.8
2265006015	Air Compressors	Commercial Equipment	4 Stroke	0.168	0.5	0.161	0.7
2265006025	Welders	Commercial Equipment	4 Stroke	0.192	0.6	0.189	0.8
2265006030	Pressure Washers	Commercial Equipment	4 Stroke	0.206	0.6	0.207	0.9
2265008005	Airport Ground Support Equipment	Airport Equipment	4 Stroke	0.208	9.1	0.201	12.1
2265010010	Other Oil Field Equipment	Industrial Equipment	4 Stroke	0.065	2.3	0.065	3.1
2267001060	Specialty Vehicle Carts	Recreational Equipment	LPG	0.237	14.2	0.218	17.9
2267002003	Pavers	Construction and Mining Equipment	LPG	0.187	11.2	0.055	4.5
2267002015	Rollers	Construction and Mining Equipment	LPG	0.110	6.6	0.000	0.0
2267002021	Paving Equipment	Construction and Mining Equipment	LPG	0.222	13.3	0.160	13.1
2267002024	Surfacing Equipment	Construction and Mining Equipment	LPG	0.171	10.2	0.055	4.5
2267002030	Trenchers	Construction and Mining Equipment	LPG	0.191	11.4	0.050	4.1
2267002033	Bore/Drill Rigs	Construction and Mining Equipment	LPG	0.235	14.0	0.210	17.3
2267002039	Concrete/Industrial Saws	Construction and Mining Equipment	LPG	0.063	3.8	0.000	0.0
2267002045	Cranes	Construction and Mining Equipment	LPG	0.222	13.3	0.131	10.7
2267002054	Crushing/Proc. Equipment	Construction and Mining Equipment	LPG	0.220	13.1	0.127	10.4
2267002057	Rough Terrain Forklifts	Construction and Mining Equipment	LPG	0.201	12.0	0.065	5.3
2267002060	Rubber Tire Loaders	Construction and Mining Equipment	LPG	0.149	8.9	0.000	0.0
2267002066	Tractors/Loaders/Backhoes	Construction and Mining Equipment	LPG	0.099	5.9	0.000	0.0
2267002072	Skid Steer Loaders	Construction and Mining Equipment	LPG	0.211	12.6	0.122	10.0
2267002081	Other Construction Equipment	Construction and Mining Equipment	LPG	0.226	13.5	0.141	11.6
2267003010	Aerial Lifts	Industrial Equipment	LPG	0.221	13.2	0.143	11.7
2267003020	Forklifts	Industrial Equipment	LPG	0.144	8.6	0.000	0.0
2267003030	Sweepers/Scrubbers	Industrial Equipment	LPG	0.113	6.7	0.000	0.0
2267003040	Other General Industrial Equipment	Industrial Equipment	LPG	0.108	6.4	0.000	0.0
2267003050	Other Material Handling Equipment	Industrial Equipment	LPG	0.218	13.0	0.116	9.5
2267003070	Terminal Tractors	Industrial Equipment	LPG	0.039	2.3	0.000	0.0
2267004066	Chippers/Stump Grinders	Lawn and Garden Equipment (Com)	LPG	0.121	7.2	0.000	0.0
2267005050	Hydro Power Units	Agricultural Equipment	LPG	0.187	11.1	0.074	6.1
2267005055	Other Agricultural Equipment	Agricultural Equipment	LPG	0.237	14.2	0.220	18.0
2267005060	Irrigation Sets	Agricultural Equipment	LPG	0.123	7.4	0.000	0.0
2267006005	Generator Sets	Commercial Equipment	LPG	0.239	14.3	0.210	17.2
2267006010	Pumps	Commercial Equipment	LPG	0.226	13.5	0.148	12.1
2267006015	Air Compressors	Commercial Equipment	LPG	0.212	12.6	0.033	2.7
2267006025	Welders	Commercial Equipment	LPG	0.190	11.3	0.027	2.3

SCC	Equipment	Classification	Engine Type	2010 Evaporative Rule Penetration	2010 Overall Control Efficiency (%)	2020 Evaporative Rule Penetration	2020 Overall Control Efficiency (%)
2267006030	Pressure Washers	Commercial Equipment	LPG	0.222	13.3	0.142	11.6
2267008005	Airport Ground Support Equipment	Airport Equipment	LPG	0.108	6.5	0.000	0.0
2268002081	Other Construction Equipment	Construction and Mining Equipment	CNG	0.225	13.5	0.139	11.4
2268003020	Forklifts	Industrial Equipment	CNG	0.148	8.8	0.000	0.0
2268003030	Sweepers/Scrubbers	Industrial Equipment	CNG	0.143	8.5	0.000	0.0
2268003040	Other General Industrial Equipment	Industrial Equipment	CNG	0.119	7.1	0.000	0.0
2268003060	AC\Refrigeration	Industrial Equipment	CNG	0.143	8.6	0.017	1.4
2268003070	Terminal Tractors	Industrial Equipment	CNG	0.043	2.5	0.000	0.0
2268005050	Hydro Power Units	Agricultural Equipment	CNG	0.000	0.0	0.000	0.0
2268005055	Other Agricultural Equipment	Agricultural Equipment	CNG	0.000	0.0	0.000	0.0
2268005060	Irrigation Sets	Agricultural Equipment	CNG	0.000	0.0	0.000	0.0
2268006005	Generator Sets	Commercial Equipment	CNG	0.240	14.4	0.218	17.8
2268006010	Pumps	Commercial Equipment	CNG	0.233	13.9	0.174	14.2
2268006015	Air Compressors	Commercial Equipment	CNG	0.215	12.9	0.043	3.5
2268010010	Other Oil Field Equipment	Industrial Equipment	CNG	0.000	0.0	0.000	0.0
2285004015	Railway Maintenance	Railroad Equipment	4 Stroke	0.184	0.4	0.183	0.6
2285006015	Railway Maintenance	Railroad Equipment	LPG	0.214	12.8	0.112	9.2

ADDITIONAL ADJUSTMENTS

Further adjustments were made to the NONROAD2004 output to ensure a consistent set of county FIPS codes across sectors and for all years. Exhibit 5-5 provides a summary of the adjustments made to remove invalid FIPS codes or add in new FIPS codes, as of 2002.

EMISSION SUMMARY BY SCENARIO

NATIONAL (48-STATE) TIER 3 SUMMARIES

A Tier 3 summary of national NONROAD model annual pollutant emissions for each scenario is presented in Exhibits 5-6a through 5-6f - the totals are presented graphically in Exhibit 5-7. These summaries do not include emissions for Alaska and Hawaii. For the *without-CAAA* scenario results, overall emissions increase between 1990 and 2000, and through 2010 and 2020. On the activity side, these emissions increase because of expected growth in equipment populations, though some categories show declines (e.g., gasoline industrial equipment). Because most nonroad engine emissions were not subject to regulation in 1990 before the CAAA were passed, emission rates for the *without CAAA* scenario are constant at 1990 levels for most engine types. In considering the *with-CAAA* scenarios for a given time period, pollutant emissions for specific nonroad categories either decrease or increase depending on the phase-in of Federal engine or fuel standards impacting emissions, and the effects of category-specific growth rates.

For the *with-CAAA* scenarios, overall VOC and CO nonroad emissions decrease between 1990 and 2000, and decrease further in 2010 and 2020. In some cases, the effects of growth outweigh the impact of VOC and CO emission standards (e.g., gasoline lawn and garden and light commercial between 2010 and 2020). Overall NO_x emissions generally decrease over time as well, (with the exception of gasoline lawn and garden and light commercial), and are lower for the *with-CAAA* case. This is due primarily to the large reductions in NO_x emissions from diesel engine standards. However, for gasoline nonroad equipment, NO_x emissions for the *with-CAAA* case relative to the *without-CAAA* case are higher for each year. This is due to the use of HC and CO-reducing technologies that control the air-fuel mixture in the cylinder, but result in increases in NO_x emissions due to the higher temperatures and increased supply of oxygen.

Overall direct $PM_{2.5}$ and PM_{10} emissions decrease over time from 1990 to 2020 for the *with-CAAA* scenarios. In addition to Federal engine standards that require reduced PM emission rates over time, the required reductions in diesel fuel sulfur levels impact PM sulfate levels and produce lower indirect contributions to ambient fine particles from diesel engines.

EXHIBIT 5-5. FIPS COUNTYCODE CORRECTIONS TO NONROAD MODEL OUTPUT

Removal of Invalid FIPS Codes

State FIPS	State Name	Invalid County FIPS	Invalid County Name	Valid County FIPS	Valid County Name	Notes
30	Montana	113	Yellowstone Park	031	Gallatin County	Yellowstone Park emissions allocated to Gallatin County (50%) and Park County (50%)
				067	Park County	
51	Virginia	560	Clifton Forge City	005	Alleghany County	All emissions reported for Clifton Forge City were added to Alleghany County

Addition of Broomfield County, Colorado (08014) to Main Section 812 Study Databases

State FIPS	State Name	County FIPS	County Name	Ratio	Notes
08	Colorado	001	Adams County	0.041882	Ratios applied to county emissions to estimate proportion of emissions now in Broomfield county: county proportions added together to estimate total emissions in Broomfield Co; remainder subtracted each from four counties.
		013	Boulder County	0.073721	
		059	Jefferson County	0.002939	
		123	Weld County	0.000055	

EXHIBIT 5-6A. NATIONAL NONROAD MODEL VOC EMISSIONS, TONS PER YEAR

		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Non-Road Gasoline	recreational	346,823	442,230	428,580	843,140	628,912	1,024,745	341,903
	construction	73,914	76,870	50,206	78,565	21,622	80,471	21,306
	industrial	80,901	38,109	22,888	22,521	6,229	9,779	2,457
	lawn & garden	970,573	1,160,782	786,848	1,417,831	430,648	1,679,121	476,166
	farm	16,746	16,779	12,580	18,664	8,165	20,334	6,565
	light commercial	232,486	296,918	165,219	398,902	101,397	501,643	122,842
	logging	10,555	14,560	11,729	20,623	7,612	26,861	9,635
	airport service	399	433	248	491	88	552	73
	railway maintenance	319	357	181	396	108	437	116
	recreational marine vessels	638,077	858,255	810,808	903,760	505,756	969,499	418,824
	Subtotal: Gasoline	**2,370,793**	**2,905,293**	**2,289,288**	**3,704,894**	**1,710,536**	**4,313,442**	**1,399,885**
Non-Road Diesel	recreational	506	603	577	746	557	874	426
	construction	94,930	112,750	92,003	139,838	61,557	168,560	37,633
	industrial	20,744	21,952	16,227	28,334	9,329	34,565	5,808
	lawn & garden	4,077	5,416	4,934	8,022	3,871	10,681	2,868
	farm	104,683	83,676	76,438	81,109	47,034	86,419	26,893
	light commercial	12,450	15,092	13,955	19,984	11,797	24,789	7,668
	logging	3,023	3,009	1,864	2,780	878	2,553	453
	airport service	1,107	1,185	945	1,719	660	2,318	460
	railway maintenance	583	686	626	855	546	1,049	340
	recreational marine vessels	1,171	1,463	1,450	1,902	1,668	2,338	1,611
	Subtotal: Diesel	**243,273**	**245,832**	**209,019**	**285,287**	**137,898**	**334,148**	**84,161**
Other	liquefied petroleum gas	51,135	66,177	65,976	86,022	26,154	105,209	5,553
	compressed natural gas	510	509	508	593	135	701	46
	Subtotal: Other Fuels	**51,645**	**66,686**	**66,484**	**86,615**	**26,289**	**105,911**	**5,599**
Total: All Sources		**2,665,710**	**3,217,810**	**2,564,790**	**4,076,796**	**1,874,723**	**4,753,500**	**1,489,644**

EXHIBIT 5-6B. NATIONAL NONROAD MODEL NOX EMISSIONS, TONS PER YEAR

		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Non-Road Gasoline	recreational	7,172	7,963	11,130	13,469	15,502	15,830	22,056
	construction	4,031	4,194	6,760	4,308	3,922	4,414	3,282
	industrial	31,239	13,771	16,278	7,092	4,583	1,741	1,043
	lawn & garden	43,030	51,156	88,549	62,980	67,780	74,902	75,929
	farm	4,336	4,262	4,823	4,830	3,581	5,270	2,732
	light commercial	15,914	20,382	36,898	27,501	31,800	34,532	36,465
	logging	187	257	425	364	503	475	611
	airport service	168	182	214	208	70	233	39
	railway maintenance	27	30	60	33	42	37	43
	recreational marine vessels	29,810	32,794	35,531	35,264	52,570	37,784	63,533
	Subtotal: Gasoline	**135,914**	**134,992**	**200,668**	**156,050**	**180,352**	**175,219**	**205,733**
Non-Road Diesel	recreational	1,279	1,615	1,561	2,116	1,765	2,622	1,674
	construction	753,314	840,108	744,295	1,047,430	588,884	1,268,852	263,953
	industrial	158,895	157,801	135,989	201,531	108,414	243,762	57,951
	lawn & garden	21,675	30,594	29,061	47,685	34,097	65,201	30,570
	farm	631,861	588,629	555,425	650,033	464,898	723,882	280,010
	light commercial	59,400	75,657	72,340	103,580	79,063	131,469	63,609
	logging	39,367	30,544	23,735	28,139	11,551	25,843	1,485
	airport service	11,346	11,581	10,360	16,668	9,105	22,465	3,764
	railway maintenance	2,703	3,228	3,052	4,082	3,027	5,047	2,081
	recreational marine vessels	30,387	37,967	37,807	49,357	45,651	60,683	47,870
	Subtotal: Diesel	**1,710,227**	**1,777,723**	**1,613,623**	**2,150,621**	**1,346,456**	**2,549,825**	**752,967**
Other	liquefied petroleum gas	189,965	246,230	245,483	321,015	106,456	393,403	35,384
	compressed natural gas	31,638	31,765	31,685	37,152	10,149	43,962	4,834
	Subtotal: Other Fuels	**221,604**	**277,996**	**277,168**	**358,167**	**116,605**	**437,365**	**40,218**
Total: All Sources		**2,067,745**	**2,190,711**	**2,091,459**	**2,664,838**	**1,643,413**	**3,162,409**	**998,918**

EXHIBIT 5-6C. NATIONAL NONROAD MODEL CO EMISSIONS, TONS PER YEAR

		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Non-Road Gasoline	recreational	1,726,365	1,940,823	1,809,891	2,960,070	2,664,655	3,464,464	2,648,120
	construction	738,938	766,913	642,736	784,773	651,296	803,753	653,784
	industrial	1,368,122	696,357	629,318	441,573	369,401	229,256	201,742
	lawn & garden	10,749,591	12,765,324	10,852,538	15,693,951	13,213,067	18,657,641	15,655,065
	farm	326,885	326,661	309,287	365,630	317,177	398,311	320,966
	light commercial	3,608,574	4,593,170	4,003,709	6,192,748	5,517,249	7,790,804	6,912,564
	logging	66,370	91,489	76,980	129,614	101,789	168,806	134,144
	airport service	6,110	6,611	5,956	7,524	4,579	8,449	4,375
	railway maintenance	6,483	7,233	6,290	8,056	7,388	8,888	8,096
	recreational marine vessels	1,650,978	2,020,735	1,940,670	2,177,771	1,921,147	2,334,301	1,915,526
	Subtotal: Gasoline	**20,248,417**	**23,215,316**	**20,277,375**	**28,761,711**	**24,767,750**	**33,864,674**	**28,454,382**
Non-Road Diesel	recreational	1,983	2,336	2,241	2,851	2,258	3,285	1,798
	construction	438,977	554,759	444,570	697,855	326,744	845,217	139,226
	industrial	80,541	90,588	66,495	117,536	57,435	143,649	15,665
	lawn & garden	14,388	18,495	17,208	26,519	16,303	34,843	12,408
	farm	432,928	387,736	348,671	413,434	240,266	457,847	125,334
	light commercial	46,820	54,469	51,283	70,189	49,658	85,308	33,688
	logging	18,446	17,528	9,493	16,186	4,992	14,865	605
	airport service	4,733	6,389	5,054	9,771	4,082	13,244	1,662
	railway maintenance	2,602	3,017	2,735	3,682	2,364	4,484	1,406
	recreational marine vessels	4,903	6,126	6,088	7,963	7,788	9,790	9,449
	Subtotal: Diesel	**1,046,321**	**1,141,443**	**953,839**	**1,365,987**	**711,890**	**1,612,532**	**341,240**
Other	liquefied petroleum gas	753,409	974,512	971,559	1,265,448	690,742	1,546,639	181,347
	compressed natural gas	128,116	127,659	127,337	148,671	58,702	175,629	22,490
	Subtotal: Other Fuels	**881,525**	**1,102,171**	**1,098,895**	**1,414,119**	**749,444**	**1,722,268**	**203,838**
Total: All Sources		**22,176,262**	**25,458,930**	**22,330,110**	**31,541,817**	**26,229,083**	**37,199,473**	**28,999,459**

EXHIBIT 5-6D. NATIONAL NONROAD MODEL PM10 EMISSIONS, TONS PER YEAR

		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Non-Road Gasoline	recreational	8,931	11,917	11,881	25,198	19,576	30,756	10,673
	construction	2,107	2,189	2,095	2,242	2,063	2,296	2,111
	industrial	852	383	223	216	104	81	43
	lawn & garden	19,272	23,100	21,332	28,255	22,807	33,406	26,748
	farm	165	165	124	185	120	201	129
	light commercial	2,230	2,841	2,258	3,830	2,368	4,818	2,964
	logging	385	531	556	752	784	979	1,020
	airport service	4	5	2	5	2	6	2
	railway maintenance	3	3	2	4	1	4	1
	recreational marine vessels	28,722	38,585	37,829	41,573	28,264	44,561	28,142
	Subtotal: Gasoline	**62,671**	**79,719**	**76,302**	**102,260**	**76,089**	**117,108**	**71,834**
Non-Road Diesel	recreational	317	364	355	433	350	482	281
	construction	91,957	84,244	74,451	100,987	51,136	121,569	20,623
	industrial	18,827	16,649	13,736	21,244	8,696	25,898	1,993
	lawn & garden	3,029	3,780	3,582	5,243	2,969	6,744	2,047
	farm	114,304	85,041	81,713	72,578	49,969	71,367	25,402
	light commercial	9,363	10,595	10,124	13,388	8,859	16,007	5,646
	logging	4,450	2,348	1,778	2,147	893	1,971	64
	airport service	1,252	1,027	913	1,347	643	1,796	239
	railway maintenance	503	521	500	543	398	616	246
	recreational marine vessels	846	1,025	1,019	1,333	826	1,638	761
	Subtotal: Diesel	**244,847**	**205,596**	**188,172**	**219,243**	**124,740**	**248,088**	**57,302**
Other	liquefied petroleum gas	892	1,155	1,152	1,506	1,501	1,845	1,839
	compressed natural gas	152	152	152	178	178	211	210
	Subtotal: Other Fuels	**1,043**	**1,307**	**1,304**	**1,684**	**1,679**	**2,055**	**2,049**
Total: All Sources		**308,562**	**286,623**	**265,778**	**323,187**	**202,507**	**367,252**	**131,185**

EXHIBIT 5-6E. NATIONAL NONROAD MODEL PM2.5 EMISSIONS, TONS PER YEAR

		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With--CAAA***
Non-Road Gasoline	recreational	8,217	10,964	10,931	23,182	18,010	28,295	9,819
	construction	1,939	2,014	1,928	2,062	1,898	2,113	1,942
	industrial	784	352	205	199	95	74	40
	lawn & garden	17,730	21,252	19,625	25,994	20,982	30,734	24,608
	farm	152	151	114	170	110	185	119
	light commercial	2,051	2,614	2,078	3,524	2,178	4,432	2,727
	logging	354	488	511	692	722	901	939
	airport service	4	4	2	5	2	6	2
	railway maintenance	3	3	2	3	1	4	1
	recreational marine vessels	26,425	35,498	34,803	38,247	26,003	40,996	25,891
	Subtotal: Gasoline	**57,658**	**73,342**	**70,198**	**94,079**	**70,001**	**107,740**	**66,087**
Non-Road Diesel	recreational	291	335	327	398	322	444	259
	construction	84,600	77,505	68,495	92,908	47,045	111,843	18,973
	industrial	17,321	15,317	12,637	19,545	8,000	23,826	1,833
	lawn & garden	2,786	3,478	3,296	4,824	2,731	6,204	1,883
	farm	105,160	78,238	75,176	66,772	45,972	65,657	23,370
	light commercial	8,614	9,747	9,314	12,317	8,151	14,726	5,194
	logging	4,094	2,160	1,635	1,975	822	1,814	59
	airport service	1,152	945	840	1,239	592	1,653	220
	railway maintenance	463	480	460	499	366	567	226
	recreational marine vessels	778	943	937	1,226	760	1,507	701
	Subtotal: Diesel	**225,259**	**189,149**	**173,118**	**201,704**	**114,760**	**228,241**	**52,718**
Other	liquefied petroleum gas	892	1,155	1,152	1,506	1,501	1,845	1,839
	compressed natural gas	152	152	152	178	178	211	210
	Subtotal: Other Fuels	**1,043**	**1,307**	**1,304**	**1,684**	**1,679**	**2,055**	**2,049**
Total: All Sources		**283,960**	**263,798**	**244,620**	**297,466**	**186,440**	**338,036**	**120,854**

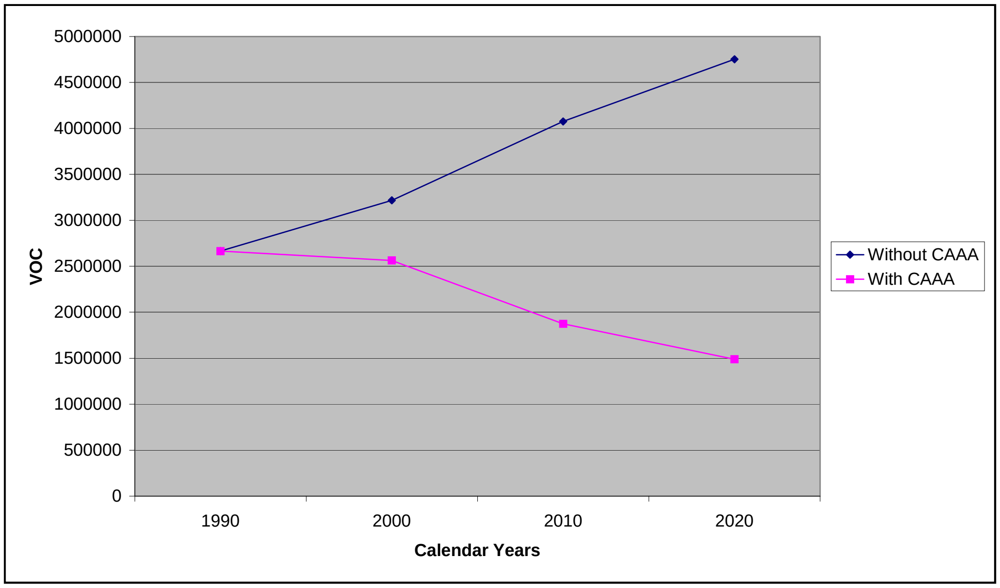
EXHIBIT 5-6F. NATIONAL NONROAD MODEL SO2 EMISSIONS, TONS PER YEAR

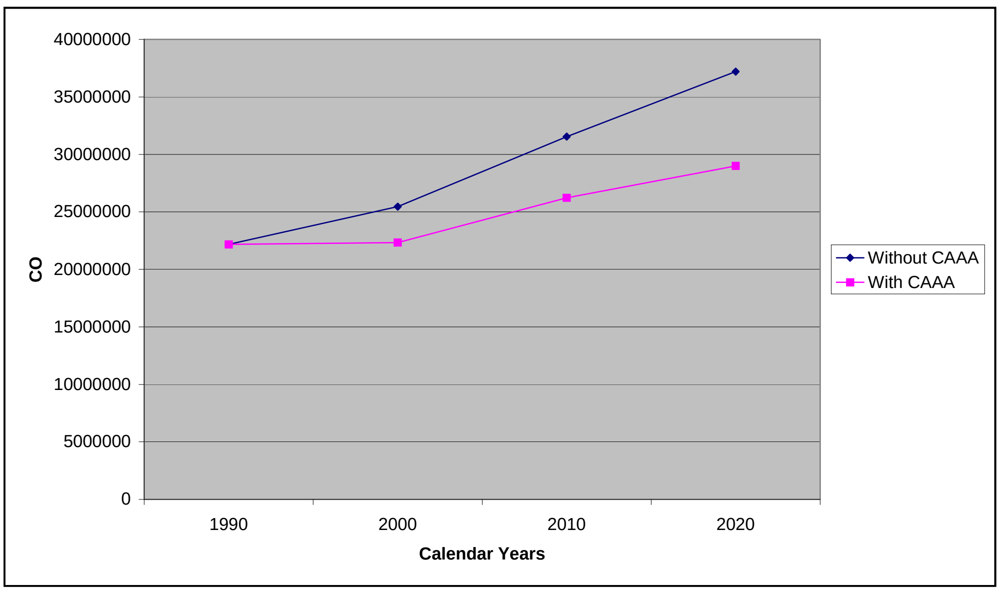
		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Non-Road Gasoline	recreational	1,239	1,409	1,390	2,266	200	2,718	244
	construction	280	291	273	298	22	305	22
	industrial	797	378	361	219	16	90	6
	lawn & garden	4,229	5,024	4,462	6,178	434	7,346	513
	farm	162	162	158	182	14	199	15
	light commercial	1,461	1,862	1,671	2,510	175	3,157	218
	logging	22	30	30	43	3	56	4
	airport service	4	4	4	5	0	5	0
	railway maintenance	3	3	3	3	0	4	0
	recreational marine vessels	1,774	2,186	2,184	2,355	204	2,524	221
	Subtotal: Gasoline	**9,971**	**11,349**	**10,537**	**14,059**	**1,069**	**16,404**	**1,245**
Non-Road Diesel	recreational	143	164	163	214	15	264	1
	construction	69,121	79,623	79,394	101,927	7,358	124,181	469
	industrial	14,400	16,192	16,164	21,015	1,519	25,574	92
	lawn & garden	2,343	3,056	3,043	4,801	346	6,565	28
	farm	52,211	50,712	50,693	61,125	4,422	70,101	293
	light commercial	6,589	7,875	7,854	10,906	788	13,934	59
	logging	3,362	2,850	2,845	2,632	190	2,417	8
	airport service	780	1,019	1,018	1,579	114	2,144	8
	railway maintenance	235	280	278	382	28	483	2
	recreational marine vessels	3,865	4,829	4,810	6,278	755	7,719	160
	Subtotal: Diesel	**153,048**	**166,601**	**166,262**	**210,859**	**15,535**	**253,381**	**1,122**
Other	liquefied petroleum gas	206	267	267	349	295	427	346
	compressed natural gas	29	29	29	34	32	40	38
	Subtotal: Other Fuels	**235**	**296**	**296**	**383**	**327**	**467**	**384**
Total: All Sources		**163,254**	**178,247**	**177,095**	**225,300**	**16,930**	**270,252**	**2,750**

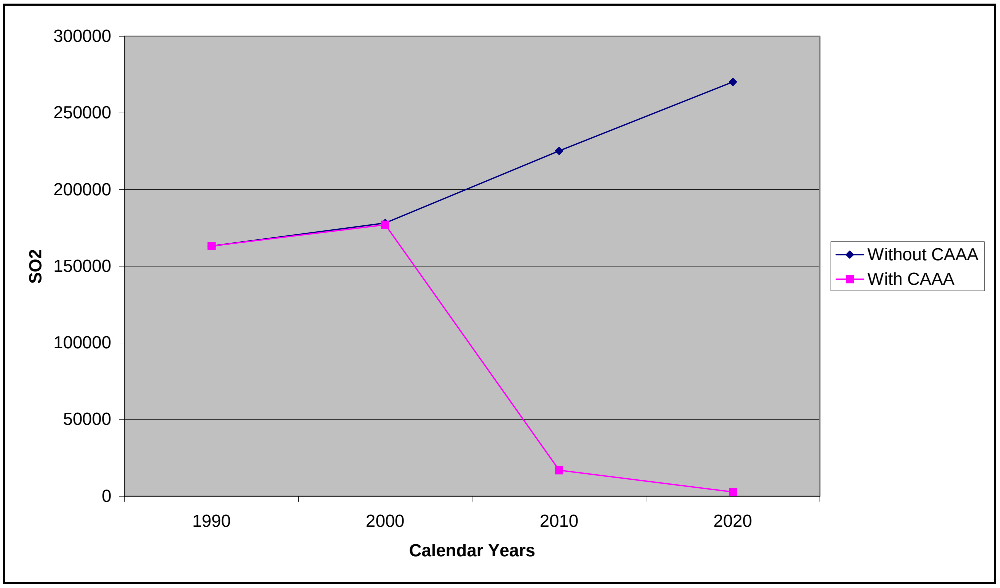
EXHIBIT 5-6G. NATIONAL NONROAD MODEL NH3 EMISSIONS, TONS PER YEAR

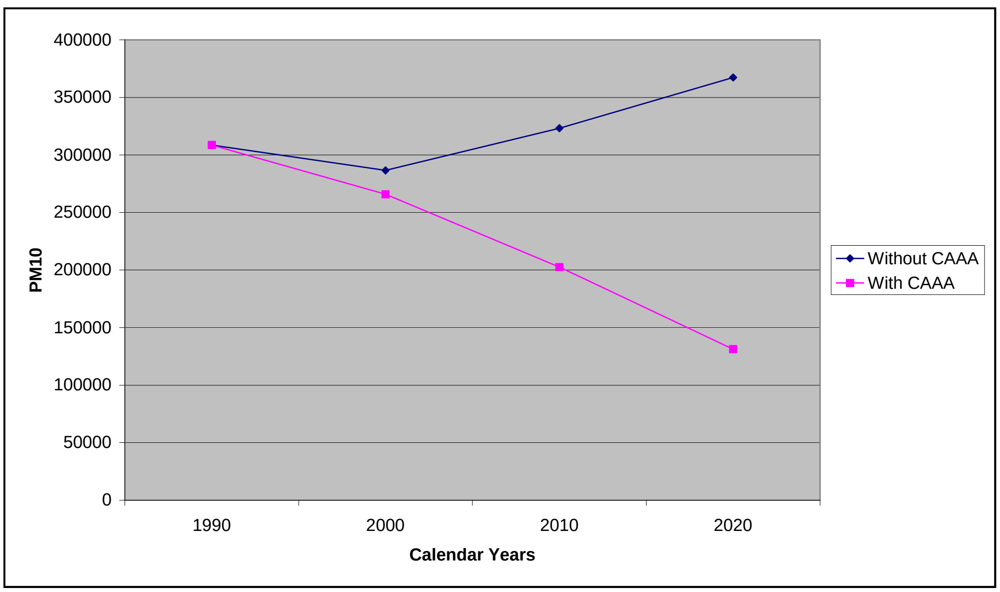
		Year/Scenario						
Tier 2 Name	**Tier 3 Name**	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
Non-Road Gasoline	recreational	92	106	105	176	168	212	187
	construction	20	21	19	22	16	22	17
	industrial	53	25	24	15	12	6	5
	lawn & garden	303	361	311	443	324	527	382
	farm	11	11	10	12	10	13	11
	light commercial	100	127	112	172	128	216	160
	logging	2	2	2	3	3	4	3
	airport service	0	0	0	0	0	0	0
	railway maintenance	0	0	0	0	0	0	0
	recreational marine vessels	134	168	167	181	161	194	169
	Total: Gasoline	**715**	**822**	**750**	**1,025**	**822**	**1,195**	**933**
Non-Road Diesel	recreational	1	1	1	1	1	2	2
	construction	368	464	462	594	591	723	721
	industrial	77	94	94	122	122	149	148
	lawn & garden	12	18	18	28	28	38	38
	farm	279	296	296	356	356	408	408
	light commercial	35	46	46	64	63	81	81
	logging	18	17	17	15	15	14	14
	airport service	4	6	6	9	9	12	12
	railway maintenance	1	2	2	2	2	3	3
	recreational marine vessels	19	24	24	32	31	39	39
	Total: Diesel	**815**	**967**	**964**	**1,223**	**1,220**	**1,470**	**1,465**
Other	liquefied petroleum gas	0	0	0	0	0	0	0
	compressed natural gas	0	0	0	0	0	0	0
	Total: Other Fuels	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total: All Sources		**1,530**	**1,789**	**1,715**	**2,248**	**2,042**	**2,665**	**2,399**

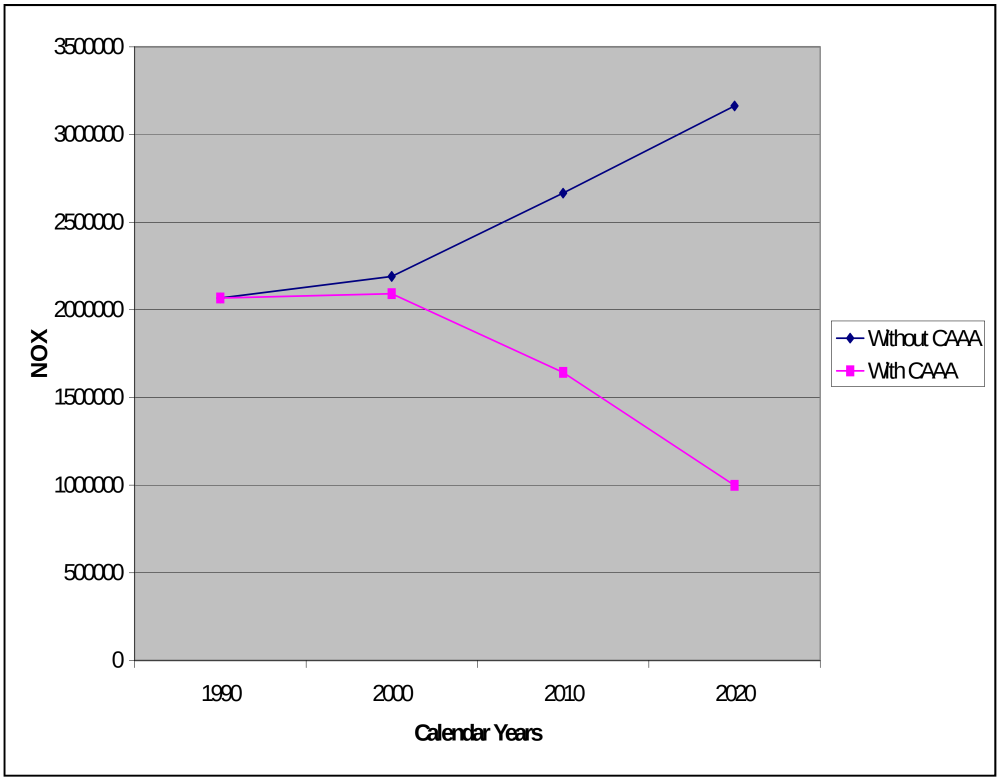
EXHIBIT 5-7. *WITH-* AND *WITHOUT-CAAA* SCENARIO NONROAD EMISSION SUMMARIESBY POLLUTANT

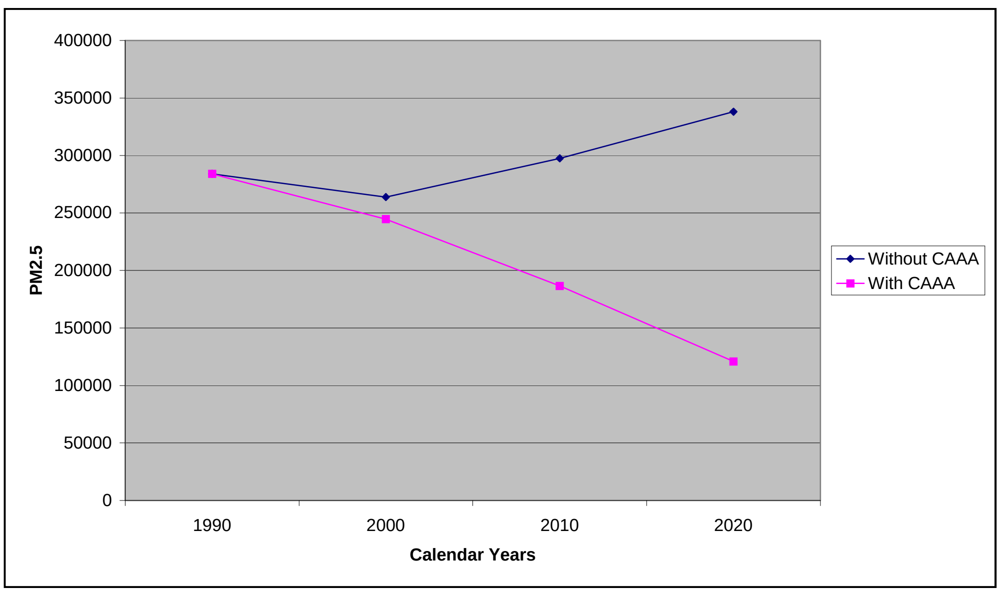


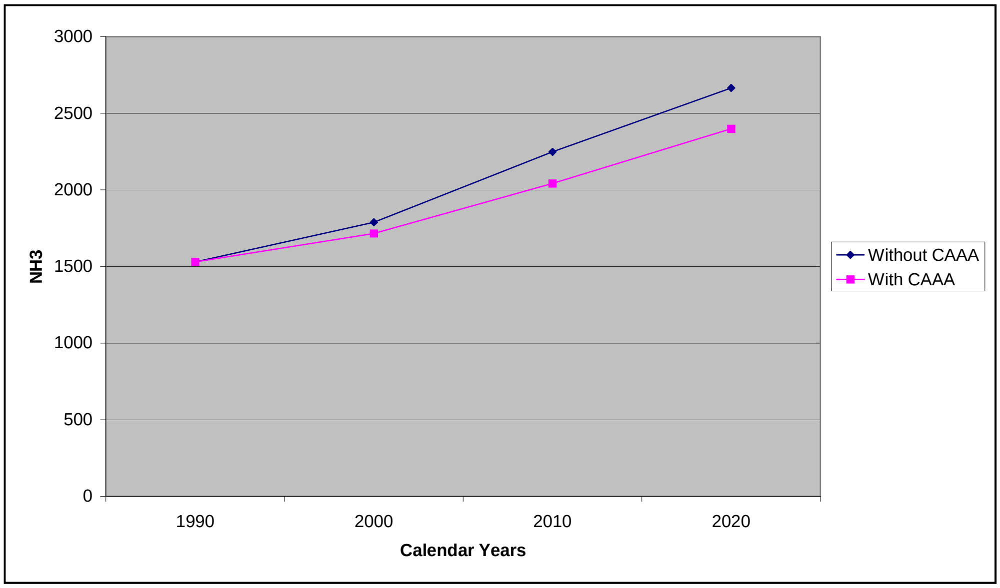



300000
250000
200000
150000
100000
50000
0
SO2
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


400000
350000
300000
250000
200000
150000
100000
50000
0
PM10
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


3500000
3000000
2500000
2000000
1500000
1000000
500000
0
NOX
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


400000
350000
300000
250000
200000
150000
100000
50000
0
PM2.5
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


3000
2500
2000
1500
1000
500
0
NH3
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA

Fuel-based emissions include SO_2 and NH_3 (see Exhibits 5-6f and 5-6g). Overall fuel consumption is estimated to increase for all categories over time, and in the absence of NH_3 controls, NH_3 emissions reflect this trend for both *with*- and *without-CAAA* scenarios. SO_2 emissions were estimated based on the amount of fuel consumed, reflecting a linear relationship between SO_2 emissions and fuel sulfur content. EPA's Federal regulations require significant decreases in the fuel sulfur levels for gasoline and diesel engines, which results in the large differences shown between the *with*- and *without-CAAA* emissions.

CALIFORNIA OFFROAD MODELING SUMMARY

ARB has developed their own model for preparing nonroad emission inventories named OFFROAD. There is a separate model for California, in part, because California sets its own off-road equipment emission standards. EPA requested that the ARB provide OFFROAD-based inventories for both *with*- and *without-CAAA* controls for the years of interest. Controlled OFFROAD inventories were available from ARB, but OFFROAD-based emissions reflecting a *without-CAAA* scenario could not be provided. For consistency, EPA NONROAD model-based emissions for California were used for both the *with*- and *without-CAAA* scenario in this analysis.

To examine the difference between these two nonroad emission models, results obtained from the *with-CAAA* NONROAD model runs for California were compared with Statewide nonroad controlled inventories based on ARB's OFFROAD model. Controlled emissions inventories for California were obtained from ARB's *Emission Inventory Data - Almanac Emission Projection Data* (ARB, 2005). The results of these comparisons at a Tier 3 source category level are shown in Exhibits 5-8a through 5-8e for VOC, NO_x, CO, $PM_{2.5}$, and SO_2. It should be noted that ARB did not estimate or report emissions for certain categories of engines included in EPA's NONROAD model, including gasoline and diesel railway maintenance, diesel recreational vehicles, and all liquefied petroleum gas engines.

ARB estimates total VOC emissions for each scenario year to be approximately 30 to 40 percent lower than NONROAD, and estimates CO emissions to be 50 to 75 percent lower than NONROAD. ARB also estimates $PM_{2.5}$ emissions to be about 10 percent lower than NONROAD on average for all years except 1990, which shows slightly higher $PM_{2.5}$ emissions based on OFFROAD. ARB's NO_x estimates are considerably higher in 1990 (+98 percent), and in 2000 (+45 percent), but are only about 20 percent higher than NONROAD for the years 2010 and 2020. Finally, ARB estimates SO_2 emissions to be 55 percent higher than NONROAD in 1990, and 163 percent higher in 2020. Overall, SO_2 emissions in 2000 and 2010 are much lower based on ARB's model (-93 percent and –52 percent, respectively). In the absence of uncontrolled data based on OFFROAD, the impact the ARB estimates would have on the differences between *with*- and *without-CAAA* cases for all 48-States cannot be determined. Note that California contributes approximately 10 percent of the total national emissions.

EXHIBIT 5-8A. COMPARISON OF SECTION 812 AND ARB-DERIVED ANNUAL VOC EMISSIONS FOR CALIFORNIA, TPY

		1990			2000			2010			2020		
Tier 2 Name	**Tier 3 Name**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**
Non-Road Gasoline	recreational	15,142	22,241	47%	19,483	20,605	6%	34,635	21,391	-38%	17,870	24,626	38%
	construction	8,250	2,122	-74%	4,680	1,477	-68%	2,264	976	-57%	2,438	959	-61%
	industrial	7,098	3,050	-57%	2,052	2,815	37%	548	1,140	108%	180	759	322%
	lawn & garden	144,780	78,822	-46%	114,804	57,234	-50%	60,821	29,149	-52%	70,039	26,864	-62%
	farm	327	1,170	258%	295	982	233%	189	833	341%	163	688	322%
	light commercial	27,281	8,843	-68%	18,971	6,870	-64%	11,839	4,483	-62%	14,870	3,563	-76%
	logging	569	2,417	325%	517	1,163	125%	332	538	62%	434	538	24%
	airport service	55	208	278%	34	253	647%	12	98	728%	10	69	585%
	railway maintenance	37	NA	NA	20	NA	NA	12	NA	NA	14	NA	NA
	recreational marine vessels	44,212	37,822	-14%	54,546	52,821	-3%	33,368	28,580	-14%	27,583	16,755	-39%
Non-Road Diesel	recreational	49	NA	NA	56	NA	NA	56	NA	NA	44	NA	NA
	construction	10,591	17,968	70%	8,939	14,043	57%	7,035	8,487	21%	4,819	5,071	5%
	industrial	2,025	3,885	92%	1,707	3,408	100%	1,032	2,499	142%	705	1,227	74%
	lawn & garden	715	477	-33%	872	334	-62%	698	183	-74%	531	3	-99%
	farm	2,068	8,959	333%	1,831	7,250	296%	1,115	4,590	312%	706	2,136	202%
	light commercial	1,481	1,773	20%	1,688	1,531	-9%	1,472	1,153	-22%	988	536	-46%
	logging	162	1,059	552%	87	427	388%	40	222	456%	21	137	558%
	airport service	157	137	-13%	135	137	1%	97	122	26%	70	81	17%
	railway maintenance	70	NA	NA	76	NA	NA	68	NA	NA	44	NA	NA
	recreational marine vessels	84	194	132%	105	232	121%	125	276	122%	124	328	164%
Other	liquefied petroleum gas	4,946	NA	NA	6,757	NA	NA	2,722	NA	NA	682	NA	NA
	compressed natural gas	40	10	-75%	50	11	-77%	14	6	-60%	6	4	-30%
		270,139	**191,156**	**-29%**	**237,704**	**171,592**	**-28%**	**158,493**	**104,727**	**-34%**	**142,339**	**84,345**	**-41%**

EXHIBIT 5-8B. COMPARISON OF SECTION 812 AND ARB-DERIVED ANNUAL NOX EMISSIONS FOR CALIFORNIA, TPY

		1990			2000			2010			2020		
Tier 2 Name	Tier 3 Name	Section 812 Study	ARB	Percent Difference	Section 812 Study	ARB	Percent Difference	Section 812 Study	ARB	Percent Difference	Section 812 Study	ARB	Percent Difference
Non-Road Gasoline	recreational	457	1,191	161%	803	1,524	90%	1,115	1,792	61%	1,290	2,058	60%
	construction	437	1,096	151%	679	754	11%	464	889	91%	419	915	119%
	industrial	2,685	7,029	162%	1,686	7,265	331%	494	3,075	522%	93	2,328	2393%
	lawn & garden	6,436	2,073	-68%	14,710	2,524	-83%	11,158	3,030	-73%	12,902	2,558	-80%
	farm	82	1,201	1367%	137	821	499%	101	849	744%	84	918	994%
	light commercial	1,760	2,977	69%	4,655	2,951	-37%	4,154	3,237	-22%	4,949	3,335	-33%
	logging	10	97	910%	20	43	111%	24	61	155%	30	61	103%
	airport service	23	904	3895%	32	1,225	3775%	11	451	4158%	6	308	4923%
	railway maintenance	3	NA	NA	8	NA	NA	5	NA	NA	6	NA	NA
	recreational marine vessels	2,154	5,568	158%	2,949	7,268	146%	4,536	11,227	148%	5,678	9,452	66%
Non-Road Diesel	recreational	124	NA	NA	151	NA	NA	176	NA	NA	172	NA	NA
	construction	84,582	164,039	94%	71,672	121,026	69%	65,865	83,714	27%	34,626	51,937	50%
	industrial	15,115	27,362	81%	14,062	21,340	52%	11,969	15,774	32%	7,087	9,476	34%
	lawn & garden	3,799	2,260	-41%	5,135	2,452	-52%	6,169	531	-91%	5,674	8	-100%
	farm	12,618	72,901	478%	14,002	53,602	283%	11,969	35,101	193%	7,397	20,392	176%
	light commercial	7,069	12,864	82%	8,763	9,944	13%	9,913	7,680	-23%	8,237	4,860	-41%
	logging	2,150	10,448	386%	1,083	4,067	276%	527	2,376	351%	77	1,305	1586%
	airport service	1,611	1,601	-1%	1,479	1,478	0%	1,337	1,246	-7%	565	764	35%
	railway maintenance	323	NA	NA	370	NA	NA	379	NA	NA	268	NA	NA
	recreational marine vessels	2,168	856	-61%	2,729	965	-65%	3,410	1,149	-66%	3,700	1,368	-63%
Other	liquefied petroleum gas	18,477	NA	NA	25,270	NA	NA	11,222	NA	NA	4,393	NA	NA
	compressed natural gas	2,485	10,924	340%	3,110	12,358	297%	1,094	5,695	420%	589	4,460	657%
		164,566	**325,389**	**98%**	**173,505**	**251,607**	**45%**	**146,092**	**177,877**	**22%**	**98,241**	**116,505**	**19%**

EXHIBIT 5-8C. COMPARISON OF SECTION 812 AND ARB-DERIVED ANNUAL CO EMISSIONS FOR CALIFORNIA, TPY

		1990			2000			2010			2020		
Tier 2 Name	**Tier 3 Name**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**
Non-Road Gasoline	recreational	98,688	106,244	8%	96,366	93,541	-3%	160,473	102,822	-36%	176,602	118,302	-33%
	construction	83,783	47,537	-43%	58,626	35,089	-40%	67,656	29,119	-57%	74,778	29,444	-61%
	industrial	121,507	59,249	-51%	54,906	50,429	-8%	30,699	48,266	57%	14,165	49,710	251%
	lawn & garden	1,589,716	510,820	-68%	1,549,253	362,430	-77%	1,934,951	243,456	-87%	2,363,369	266,472	-89%
	farm	6,504	31,424	383%	7,516	25,200	235%	8,052	22,991	186%	9,028	22,143	145%
	light commercial	433,437	190,600	-56%	460,887	151,119	-67%	658,655	129,187	-80%	855,475	120,297	-86%
	logging	3,608	16,740	364%	3,245	6,377	97%	4,235	4,326	2%	5,800	4,326	-25%
	airport service	874	3,511	302%	821	3,911	376%	648	3,123	382%	640	3,151	392%
	railway maintenance	781	NA	NA	728	NA	NA	886	NA	NA	1,006	NA	NA
	recreational marine vessels	117,353	205,463	75%	131,318	251,101	91%	134,459	219,049	63%	138,933	206,876	49%
Non-Road Diesel	recreational	192	NA	NA	217	NA	NA	225	NA	NA	184	NA	NA
	construction	49,164	81,941	67%	43,465	51,731	19%	36,640	40,544	11%	18,755	38,528	105%
	industrial	7,798	14,906	91%	6,911	11,904	72%	6,468	9,354	45%	1,879	8,031	327%
	lawn & garden	2,521	1,432	-43%	3,039	1,532	-50%	2,944	220	-93%	2,300	12	-99%
	farm	8,538	32,084	276%	8,487	24,555	189%	5,835	17,666	203%	3,166	14,864	370%
	light commercial	5,565	6,235	12%	6,198	5,103	-18%	6,207	4,261	-31%	4,341	3,676	-15%
	logging	998	4,465	347%	457	1,542	238%	221	1,184	436%	31	1,161	3654%
	airport service	672	748	11%	722	670	-7%	599	642	7%	249	647	160%
	railway maintenance	310	NA	NA	331	NA	NA	295	NA	NA	180	NA	NA
	recreational marine vessels	350	356	2%	439	426	-3%	582	507	-13%	731	603	-17%
Other	liquefied petroleum gas	72,734	NA	NA	99,332	NA	NA	74,064	NA	NA	22,254	NA	NA
	compressed natural gas	9,924	25,791	160%	12,396	28,898	133%	6,298	32,073	409%	2,712	35,289	1201%
		2,615,018	**1,339,546**	**-49%**	**2,545,659**	**1,105,559**	**-57%**	**3,141,091**	**908,788**	**-71%**	**3,696,579**	**923,533**	**-75%**

EXHIBIT 5-8D. COMPARISON OF SECTION 812 AND ARB-DERIVED ANNUAL PM2.5 EMISSIONS FOR CALIFORNIA, TPY

		1990			2000			2010			2020		
Tier 2 Name	**Tier 3 Name**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**
Non-Road Gasoline	recreational	401	66	-83%	577	77	-87%	1,104	89	-92%	551	102	-82%
	construction	218	19	-91%	183	176	-4%	204	226	11%	230	237	3%
	industrial	72	26	-64%	19	32	62%	9	36	290%	4	38	966%
	lawn & garden	2,762	1,151	-58%	3,065	1,051	-66%	3,389	706	-79%	4,099	823	-80%
	farm	3	8	156%	3	24	717%	3	33	988%	4	37	925%
	light commercial	244	74	-70%	252	211	-16%	274	336	23%	355	350	-2%
	logging	19	35	85%	23	29	30%	32	32	0%	43	32	-26%
	airport service	1	3	354%	0	4	1129%	0	5	1523%	0	5	1417%
	railway maintenance	0	NA	NA	0	NA	NA	0	NA	NA	0	NA	NA
	recreational marine vessels	1,885	1,260	-33%	2,508	1,909	-24%	1,940	3,103	60%	2,000	3,687	84%
Non-Road Diesel	recreational	28	NA	NA	32	NA	NA	32	NA	NA	27	NA	NA
	construction	9,678	10,520	9%	6,813	7,089	4%	5,373	5,098	-5%	2,651	3,267	23%
	industrial	1,650	2,164	31%	1,318	1,659	26%	890	1,370	54%	215	780	263%
	lawn & garden	488	206	-58%	581	157	-73%	492	120	-76%	348	4	-99%
	farm	2,027	4,829	138%	1,743	3,218	85%	1,070	2,227	108%	577	1,296	125%
	light commercial	1,023	912	-11%	1,124	686	-39%	1,017	578	-43%	667	346	-48%
	logging	230	646	181%	76	225	194%	37	137	275%	3	83	2405%
	airport service	163	120	-26%	119	102	-14%	87	89	3%	33	54	64%
	railway maintenance	55	NA	NA	56	NA	NA	45	NA	NA	29	NA	NA
	recreational marine vessels	55	23	-59%	68	23	-65%	57	29	-48%	54	35	-34%
Other	liquefied petroleum gas	86	NA	NA	118	NA	NA	167	NA	NA	229	NA	NA
	compressed natural gas	12	57	376%	15	66	341%	19	73	274%	25	80	218%
		21,101	**22,118**	**5%**	**18,692**	**16,738**	**-10%**	**16,240**	**14,287**	**-12%**	**12,142**	**11,254**	**-7%**

EXHIBIT 5-8E. COMPARISON OF SECTION 812 AND ARB-DERIVED ANNUAL SO2 EMISSIONS FOR CALIFORNIA, TPY

		1990			2000			2010			2020		
Tier 2 Name	**Tier 3 Name**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**	**Section 812 Study**	**ARB**	**Percent Difference**
Non-Road Gasoline	recreational	57	184	222%	63	43	-32%	10	48	355%	14	53	294%
	construction	31	12	-63%	26	10	-60%	2	11	387%	3	12	350%
	industrial	72	48	-33%	35	49	42%	2	54	3297%	1	57	9811%
	lawn & garden	624	127	-80%	666	150	-77%	67	170	155%	81	191	134%
	farm	3	10	209%	4	9	108%	0	10	2355%	0	10	2220%
	light commercial	174	53	-70%	203	55	-73%	22	61	179%	28	65	128%
	logging	1	5	326%	1	3	138%	0	3	2099%	0	3	1566%
	airport service	1	5	759%	1	7	1045%	0	8	16106%	0	9	15133%
	railway maintenance	0	NA	NA	0	NA	NA	0	NA	NA	0	NA	NA
	recreational marine vessels	127	123	-3%	158	153	-3%	15	185	1112%	17	208	1118%
Non-Road Diesel	recreational	14	NA	NA	16	NA	NA	2	NA	NA	0	NA	NA
	construction	7,718	9,421	22%	7,470	86	-99%	786	96	-88%	56	100	79%
	industrial	1,405	1,508	7%	1,701	13	-99%	170	14	-92%	11	14	25%
	lawn & garden	411	0	-100%	538	0	-100%	63	0	-100%	5	0	-100%
	farm	1,054	7,047	569%	1,332	348	-74%	123	36	-71%	9	35	297%
	light commercial	784	700	-11%	952	6	-99%	99	7	-93%	8	7	-5%
	logging	181	1,037	472%	126	3	-98%	8	3	-63%	0	3	703%
	airport service	111	3	-97%	146	0	-100%	17	1	-93%	1	1	9%
	railway maintenance	28	NA	NA	34	NA	NA	3	NA	NA	0	NA	NA
	recreational marine vessels	276	2	-99%	347	0	-100%	56	0	-100%	12	0	-100%
Other	liquefied petroleum gas	20	NA	NA	27	NA	NA	33	NA	NA	43	NA	NA
	compressed natural gas	2	6	163%	3	6	118%	3	7	98%	5	7	57%
		13,095	**20,291**	**55%**	**13,849**	**942**	**-93%**	**1,483**	**715**	**-52%**	**296**	**776**	**163%**

A more detailed evaluation and explanation of category-specific differences is documented in Appendix D. In summary, while the results in Exhibit 5-8 may initially seem troubling, the analysis in Appendix D suggests that the large discrepancies result mainly from differences in equipment activity, category-specific future emission standards, and variations in fuel input data (e.g., fuel sulfur content). Some of the differences are substantial when comparing all categories combined for a given pollutant. However, one large discrepancy for the gasoline lawn and garden category is attributable to outdated data on equipment populations. When updated with new survey data from California, the difference is expected to narrow substantially.

In addition, more stringent State-level fuel sulfur requirements in California than the rest of the U.S. explain the differences observed in SO_2 emission estimates shown in Exhibit 5-8e. Using California's fuel sulfur levels specified by ARB in place of the national defaults for California would result in more comparable emissions for SO_2.

Overall, we conclude from this sensitivity analysis that, because the differences between NONROAD and OFFROAD for most categories can be explained, it is reasonable to use the results of NONROAD modeling for California, with one exception: fuel sulfur content input data.

CONSTRUCTION EQUIPMENT SENSITIVITY ANALYSES

The Project Team's decision to use the NONROAD model was endorsed by the Council AQMS as the most appropriate tool for estimating non-road mobile source emissions outside of California. However, recent studies by States suggest that activity factors for construction vehicles may differ substantially from the values included in the NONROAD model. Based on these findings, the AQMS suggested that the Project Team conduct sensitivity analyses that specifically address this uncertainty. The Project Team therefore conducted a comparison of the NONROAD results with results of a sensitivity analysis incorporating three other regional/local studies. Appendix E presents the detailed results of that analysis, which we summarize briefly here.

Nonroad "activity factors" are comprised of several variables, including equipment population, engine horsepower and load factor, and annual hours of use. Some of the studies questioning the validity of the NONROAD activity factors concluded that NONROAD underestimates annual hours of use per unit of equipment and overestimates total equipment populations. Because these changes offset each other (at least partially), the overall effect on activity is unclear.

Based on the emission estimation equation, the relationship between emissions and each activity variable is linear. Activity for nonroad equipment is calculated using the following equation:

Activity = Power x Load Factor x Time x Pop

Activity	=	activity (horsepower [hp]-hours)
Power	=	average rated engine power (hp)
Load Factor	=	engine load factor (average proportion of rated power)
Time	=	hours of use (hours)
Pop	=	equipment population

The comparisons we conducted focus on base year emissions for 2000. Note that revisions to hours of use data also affect rates of scrappage and phase-in of new, cleaner engines, which will also affect future year emissions. To gauge the potential significance of these activity factors, the Project Team compared year 2000 emissions developed from default activity inputs included in NONROAD with emissions developed from revised inputs from three local construction activity studies. The three specific studies include: (1) Lake Michigan Air Directors Consortium (LADCO) Nonroad Emissions Inventory Project; (2) Clark County-Wide Inventory of Non-road Engines Project; and (3) Houston-Galveston Area Diesel Construction Emissions Project. We first generated annual emission estimates for the geographic areas covered by the surveys using NONROAD2004 and all default data inputs. We then adjusted the NONROAD model activity inputs using the reported survey results to generate revised emission estimates for comparison. This analysis focused on five priority construction equipment applications, or source classification codes (SCCs). In addition, because the base activity is the same for all pollutants, and differences in pollutant estimates are due to differences in emission rates, the analysis was limited to oxides of nitrogen (NOx) emissions.

In summary, this analysis shows that local surveys of nonroad equipment populations and activity produce NOx emission estimates that can be considerably higher or lower than estimates made using EPA's NONROAD model defaults. For both LADCO studies, overall NOx emissions are higher in the local area study than in the section 812 analysis, as emissions increases for the three largest equipment types outweigh decreases in those for the other two equipment types studied. For Clark County, much lower equipment populations for all surveyed source categories lead to a much lower estimate of construction equipment NOx emissions for the area. Finally, for the Houston area study, lower estimated equipment activity for four types contribute to an overall NOx emission decrease for the equipment types studied.

Assuming that national populations estimated by NONROAD are a reliable measure of the total in-use national engine populations, which we believe is reasonable based on our review of the PSR survey data, then lower estimates of equipment populations based on surveys in certain areas would be expected to be offset by increases in other areas, and vice versa. The PSR survey was conducted to generate national estimates, however, so the differences observed at the local level suggest that there is considerable variability in the construction equipment emission estimates for any individual geographic area that might not be adequately addressed by careful activity factor allocation schemes. In addition, the differences also imply that use of NONROAD default data might lead to some errors in performing any local controls analysis to simulate how an area might respond to 8-hour ozone and $PM_{2.5}$ NAAQS control requirements. Control decisions would be expected to be significantly different in areas like Clark County, NV depending on whether national defaults or local survey data are used to determine the importance of off-road construction equipment. We conclude that these results provide an important basis for conducting subsequent uncertainty analyses for impact of Federal nonroad sector regulations, in particular as we consider the identification of local controls to meet NAAQS requirements.

ANALYSIS OF FUEL CONSUMPTION PROJECTIONS IN NONROAD AND AEO2005

As noted earlier in this chapter, the Project Team used an alternate approach to project NONROAD source category growth, compared to other emissions sectors. For most other energy-based source sectors for the Section 812 analysis, we used *Annual Energy Outlook 2005* (AEO2005) fuel projections to forecast activity/emissions for the forecast years of interest (2010 and 2020). For the NONROAD model sector, the Project Team instead developed regional growth rates that reflect AEO2005 socioeconomic forecasts that have been normalized to the NONROAD model national growth rates. We found it infeasible to use AEO2005 fuel projections directly in NONROAD, because of concerns about how to implement changes in NONROAD2004 variables to yield consistently reasonable values that result in fuel consumption growth rates that match AEO2005 projections, and the lack of targeted AEO2005 fuel consumption forecasts for some NONROAD categories.

To reflect AEO energy forecasts in NONROAD we would need to develop equipment population growth rates that would result in fuel consumption estimates equivalent to what AEO projects. As indicated in equation (1) below, this would be very difficult to implement because of the many variables that affect fuel consumption estimates. Fuel consumption in the NONROAD model is a function of many variables including population, brake-specific fuel consumption (BSFC), average horsepower, load factor, and hours of use per year. Brake-specific fuel consumption is a measure of the fuel consumed per unit horsepower and hours of operation per year. Because these variables vary by SCC and within SCC, it would be arbitrary as to how these could be adjusted to yield the AEO2005 fuel forecasts.

$$F = BSFC * A * L * P * N \qquad \text{Eq. (1)}$$

where:
- F = Fuel consumption, (gallon/year)
- BSFC = Brake-specific fuel consumption, (gallon/hp-hr)
- A = Equipment activity, (hours/year)

L = Load factor, (proportion of rated power used on average basis)

P = Average rated power for modeled engines, (hp)

N = Equipment population

Another concern was that in changing the overall national growth rates, we would need to review and possibly change scrappage rates for consistency.

Matching AEO2005 fuel-based growth indicators were not identified for all equipment categories in NONROAD. Some forecasts (e.g., for commercial and industrial fuel use) were not specific to the nonroad transportation sector and include stationary and/or onroad fuel use as well. Population projections were determined to be the best available data for the Lawn and Garden, Logging, and Land-based Recreational Equipment categories. The best available data were used in the growth rate comparison described in more detail below. Further, it should be noted that NONROAD's projection methodology was developed to capture expected market shifts in engine types for specific categories over time (e.g., more new diesel construction and industrial engines replacing gasoline-fueled engines over time), which may not be reflected in the AEO2005 projections. Finally, the NONROAD data accounts for expected changes in fuel efficiency over time for each of the relevant categories; but it is not clear whether the AEO2005 data reflect such a highly resolved forecast for this sector. As a result, we believe use of the NONROAD fuel consumption growth rates, while potentially inconsistent with the approach used in other sectors, provides the best basis to evaluate the emissions reductions and costs attributable to CAAA regulations for this study.

In order to assess the degree to which AEO2005 and NONROAD2004 growth rates differ, the Project Team compared the two sets of rates. For specific nonroad categories, we compared AEO2005 fuel consumption growth rates to growth rates calculated based on fuel consumption resulting from NONROAD2004 national runs. Exhibit 5-9 shows compound annual growth rates for the time period 2002 to 2015 calculated from AEO2005 data, and similarly calculated growth rates from NONROAD2004. See the footnotes in the table for the data used in computing growth rates.

Exhibit 5-9 indicates substantial differences in the AEO2005 and NONROAD model growth rates for certain categories. Note however, that as stated above, some of the fuel consumption forecasts are not specific to off-road equipment or engine (i.e., fuel) types. For diesel engines, AEO2005 growth rates are significantly lower than NONROAD growth rates (with the exception of the logging category). For gasoline, CNG and LPG-powered engines, the AEO2005 growth rates are higher than NONROAD for some categories, but lower for others. For two gasoline categories (Farm, Lawn & Garden) the growth rates are equivalent. It should be noted that growth rates calculated based on NONROAD2004 equipment populations and fuel consumption match for diesel engines, but differ for gasoline, CNG, and LPG engines. This is because the brake-specific fuel consumption factors for each diesel SCC are constant with time. The gas, LPG, and CNG SCCs have lower BSFCs with future technology types (i.e., they are more fuel efficient), so that the fuel consumption growth is less than the corresponding engine population growth.

In addition to comparing growth rates, we also compared the actual and implied forecast consumption estimates from the two sources (in gallons) for a specific forecast year. Data to perform the comparison of forecast consumption was most readily available for the year 2015. The Project Team first identified data used in the NONROAD model for the years 2002 and 2015. We then applied the AEO growth factors reported in Exhibit 5-9 to the 2002 NONROAD consumption estimates. Using AEO 2015 fuel consumption forecasts directly would have been misleading because, as stated above, the AEO estimates also reflect activities in other areas beyond the scope of the NONROAD model. The results or our comparison are presented in Exhibit 5-10 below.

Our results indicate that the NONROAD fuel consumption estimates are generally higher than estimates that would have resulted if we had used the AEO growth rates in our forecasts. In particular, NONROAD diesel fuel consumption estimates summed across all categories are 25 percent higher than the comparable AEO-based estimates. It is not clear why this difference would be so large, but it may be due to different projections of future fuel prices - the AEO data is more recent and may reflect the beginning stages of the recent increase in diesel fuel prices, although most of the recent increases occurred well after AEO 2005 was released. The total gasoline and LPG fuel consumption estimates are roughly equivalent from the two methods, although the distribution across sectors differs.

There is also a very notable difference in compressed natural gas usage in the farm industry. Further research indicated that the CNG usage on farms is almost entirely for irrigation systems. The NONROAD model projects that CNG-fired irrigation will be entirely converted to electric by 2015. That projection is consistent with the Project Team's research. Much of the impetus for the ongoing changeover is attributed to rising fossil fuel costs. In addition, electric systems require less maintenance, reduce labor and transportation costs (farmers do not have to drive out to their fields to check on them as often) and help conserve water. There are also anecdotal reports of financial incentives being offered in places such as Nebraska and Central California for sources that make the switch. An estimated 5,700 diesel irrigation sources are in use in Central California. If these were to switch to electric, reductions would total 11,600 tons of NOx and 860 tons of PM annually. The AEO-based estimates are based on a broader index of farm activity - use of the AEO estimates, therefore, would have led us to overlook this type of baseline trend in nonroad engine usage.

EXHIBIT 5-9 COMPARISON OF AEO AND NONROAD COMPOUND ANNUAL FUEL CONSUMPTION GROWTH RATES FROM 2002 TO 2005

Fuel	**Diesel**		**Gasoline**		**LPG**		**Compressed Natural Gas**	
Model	**AEO[1]**	**NONROAD[2]**	**AEO[1]**	**NONROAD[2]**	**AEO[1]**	**NONROAD[2]**	**AEO[1]**	**NONROAD[2]**
Construction	0.60%	2.34%	0.90%	-0.90%	0.50%	0.32%	0.80%	0.65%
Farm	0.30%	2.13%	0.50%	0.49%	0.50%	-1.38%	0.70%	-100.00%
Industrial	0.70%	2.48%	0.70%	-7.45%	0.90%	0.71%	0.70%	0.04%
Light Commercial	2.20%	2.99%	0.20%	1.78%	0.30%	3.24%	1.10%	1.41%
Aircraft Ground Support	2.30%	3.85%	2.30%	-0.23%	2.30%	1.92%	NA	NA
Rail Support	0.80%	2.86%	NA	0.19%	NA	0.42%	NA	NA
Recreational Marine	1.10%	2.44%	1.10%	-0.06%	NA	NA	NA	NA
Lawn & Garden	0.90%	3.93%	0.90%	0.87%	0.90%	0.18%	NA	NA
Recreational Land-Based	0.90%	2.44%	0.90%	3.61%	0.90%	0.02%	NA	NA
Logging	0.90%	-0.90%	0.90%	1.25%	NA	NA	NA	NA

[1] AEO 2005
[2] Calculated from NONROAD Fuel Consumption Estimates

EXHIBIT 5-10. COMPARISON OF NONROAD AND AEO FUEL CONSUMPTION ESTIMATES (GALLONS CONSUMED)

Panel 1: NONROAD Estimates								
Emissions	**Diesel**		**Gasoline**		**LPG**		**Compressed Natural Gas**	
Sector	**2002**	**2015**	**2002**	**2015**	**2002**	**2015**	**2002**	**2015**
Construction	5,386,482,130	7,275,991,808	146,770,717	130,449,979	24,080,938	25,101,175	47,316,484	51,459,956
Farm	3,394,931,746	4,467,317,589	82,368,554	87,827,386	389,347	325,018	6,721,865,904	0
Industrial	1,093,770,519	1,504,809,449	165,682,317	60,573,246	2,021,966,353	2,215,536,316	138,324,779,240	138,997,100,742
Light Commercial	543,014,210	796,809,720	904,499,783	1,137,833,628	119,547,720	180,913,045	57,027,822,617	68,411,382,313
Aircraft Ground Support	73,363,305	119,869,933	2,202,916	2,137,905	2,256,861	2,891,255	N/A	N/A
Rail Support	19,251,095	27,773,317	1,329,501	1,362,546	63,065	66,635	N/A	N/A
Recreational Marine	281,512,929	385,295,220	1,311,942,787	1,302,541,295	N/A	N/A	N/A	N/A
Lawn & Garden	216,979,057	358,001,432	2,464,814,039	2,759,476,769	19,232,279	19,692,072	N/A	N/A
Recreational Land-Based	11,303,246	15,470,286	935,927,201	1,484,870,852	1,285,696	1,288,664	N/A	N/A
Logging	179,944,381	159,928,762	19,472,975	22,889,406	N/A	N/A	N/A	N/A
TOTAL	11,200,552,617	15,111,267,516	6,035,010,789	6,989,963,012	2,188,822,259	2,445,814,180	202,121,784,244	207,459,943,011
Panel 2: AEO-based Estimates (using NONROAD 2002 base)								
	2015	**NR/AEO**	**2015**	**NR/AEO**	**2015**	**NR/AEO**	**2015**	**NR/AEO**
Construction	5,822,090,779	1.25	164,901,489	0.79	25,694,028	0.98	52,480,671	0.98
Farm	3,529,743,740	1.27	87,886,110	1.00	415,428	0.78	7,359,917,760	0.00
Industrial	1,197,593,225	1.26	181,409,186	0.33	2,271,742,408	0.98	151,454,821,326	0.92
Light Commercial	720,564,464	1.11	928,301,061	1.23	124,294,933	1.46	65,743,347,375	1.04
Aircraft Ground Support	98,596,642	1.22	2,960,609	0.72	3,033,109	0.95	N/A	N/A
Rail Support	21,352,186	1.30	N/A	N/A	N/A	N/A	N/A	N/A
Recreational Marine	324,536,365	1.19	1,512,446,144	0.86	N/A	N/A	N/A	N/A
Lawn & Garden	243,782,754	1.47	2,769,295,628	1.00	21,608,067	0.91	N/A	N/A
Recreational Land-Based	12,699,550	1.22	1,051,543,470	1.41	1,444,520	0.89	N/A	N/A
Logging	202,173,137	0.79	21,878,496	1.05	N/A	N/A	N/A	N/A
TOTAL	12,173,132,842	1.24	6,720,622,193	1.04	2,448,232,494	1.00	224,610,567,132	0.92

CHAPTER 6 | ON-ROAD VEHICLES

OVERVIEW OF APPROACH

On-road vehicles include automobiles, light trucks, motorcycles, heavy-duty trucks and other vehicles that are registered for use on roads and highways. They represent a major category of air pollutants emissions specifically addressed in both the original 1970 Clean Air Act and subsequently addressed with more stringent controls in the CAAA of 1990. In general, regulation of this sector is conducted at the Federal level, with some exceptions noted below (most significantly for California). Typically, new requirements for tailpipe controls, operating refinements, evaporative emissions controls, or engine modifications apply only to new vehicles; EPA's recent pursuit of retrofit controls for diesel engines is a prominent exception. The impact of new regulations therefore depends significantly on assumptions related to the demand for new vehicles of differing types (and therefore potentially differing emissions rates), the rate of scrappage of older vehicles which tend to emit at higher rates than new vehicles, and the distribution of miles driven by vehicle class. For these reasons, the approach to estimating emissions for this sector must take careful account of the timing of regulations and incorporate the latest information on demand for vehicles and demand for miles driven by vehicle class.

The general procedure we applied for calculating historic and projection year on-road vehicle emissions was to multiply activity in the form of vehicle miles traveled (VMT) by pollutant-specific emission factor estimates. Emission factors for these pollutants were generated using the EPA's latest motor vehicle emission factor model MOBILE6.2 (EPA, 2003). MOBILE supplies emissions factors in units of grams per mile traveled for each criteria pollutant, by vehicle class. The emissions factors generated are then applied to estimates of vehicle miles traveled, by class, to estimate total emissions for each pollutant. Because California's emission standards differ from those for the rest of the nation and cannot be accurately modeled with MOBILE6.2, emission factor estimates generated by the California Air Resources Board (ARB) were used for the California emission calculations in 2000, 2010, and 2020.[46]

[46] Some non-California States have elected to adopt the California motor vehicle emission standards in accordance with Section 177 of the CAAA. The emission effects of these State adoptions have not been incorporated in this analysis, but we believe the impact of the California emissions standards on criteria pollutants, relative to the Federal standards adopted to date, are slight, because the Federal standards reflect virtually all but the most recent California standards.

Emission factors for all pollutants were developed for county-level groups with common control programs within each State. For each State, a single set of monthly average State-level temperatures are used for each year modeled. Control program inputs such as inspection and maintenance programs and fuel programs are specified at the county level. Temporally, emissions are calculated by month and summed to develop annual emission estimates. Two MOBILE6.2 input parameters, common to both the historical years and projection year modeling, are speed and temperature. Other parameters, which vary by scenario or year, are discussed under the sections describing the 1990 emissions and the control scenarios.

SPEED

Emission factors were estimated for nine different travel speeds. These speeds were developed using Highway Performance Monitoring System average travel speed data for the years 1987 through 1990 (DOT, 2000). The average travel speed for each vehicle type/roadway functional classification combination varied less than one mile per hour over the four year span. To reduce the number of speeds to be modeled, the Highway Performance Monitoring System speeds were rounded to the nearest five miles per hour. The 1990 speeds are used for all projection years, as well. Exhibit 6-1 lists the speeds which are used for each vehicle type/functional road system combination. The SCC uniquely defines the vehicle type/roadway classification, and is thus used to determine which speed to model (the emission factor data base contains a speed indicator).

TEMPERATURE

Monthly temperatures at the State level are used as input to MOBILE6.2 for calculating the on-road vehicle emission factors. Actual 1990 and 2000 temperatures were used to estimate base year emission factors. For the projection years, 30-year average temperatures (BOC, 1992) are used. Temperatures for a representative city were chosen for each State. Detailed temperature data used can be found in Appendix L.

GROWTH PROJECTIONS

2000 VMT

The VMT data used to model the year 2000 started with the 2000 NEI VMT database. However, for State or local areas that had provided their own VMT data to EPA for use in the 1999 NEI, the resulting 1999 NEI VMT data were grown to 2000.

2010 AND 2020 VMT PROJECTIONS

The resultant 2000 VMT database was projected to 2010 and 2020 using the following data sources: the *AEO 2005* projections of national VMT; the *AEO 2005* State-level population projections; Woods and Poole county-level population projections; and EPA's MOBILE6.2 default VMT mixes by vehicle type.

The *AEO 2005* State-level population projections were first allocated to counties, as described in Chapter 2. The 2000, 2010, and 2020 national VMT data from the *AEO* were distributed among the 28 MOBILE6 vehicle classes. The *AEO* data are for three vehicle classes, as shown in Exhibit 6-2. For each of the three calendar years (2000, 2010, and 2020), a MOBILE6 run was generated using model defaults. The output database files provide the default VMT mix projected by the model for each of these three years. The 28 MOBILE6 vehicle categories were matched to the three vehicle categories used in the DOE *AEO* projections as shown in Exhibit 6-3. This table also shows the default MOBILE6 VMT fractions for the three years (EPA, 2003). Next, within each of the three DOE vehicle categories, the MOBILE6 VMT fractions were normalized such that the sum of the VMT fractions for all MOBILE6 vehicle classes within one of the DOE vehicle categories would sum to 1. These fractions are shown in Exhibit 6-3 in the columns labeled *VMT Fraction by DOE Vehicle Type*. Finally, the AEO VMT from Exhibit 6-2 for each of the three DOE vehicle classes was multiplied by the corresponding VMT fraction for each of the MOBILE6 vehicle classes included in the DOE vehicle class. The resulting VMT distribution by the 28 MOBILE6 vehicle types is shown in Exhibit 6-3 in the columns labeled *Allocated DOE VMT*. It should be noted that these VMT values were used in developing the VMT growth factors, but are not necessarily the resulting projected VMT data.

EXHIBIT 6-1. AVERAGE SPEEDS MODELED BY ROAD TYPE AND VEHICLE TYPE (MILES PER HOUR)

	Rural						Urban					
	Interstate	**Principal Arterial**	**Minor Arterial**	**Major Collector**	**Minor Collector**	**Local**	**Inter state**	**Other Freeways& Expressways**	**Principal Arterial**	**Minor Arterial**	**Collector**	**Local**
Light-Duty Vehicle (LDV)	60	45	40	35	30	30	45	45	20	20	20	20
Light-Duty Truck (LDT)	55	45	40	35	30	30	45	45	20	20	20	20
Heavy-Duty Vehicle (HDV)	40	35	30	25	25	25	35	35	15	15	15	15

EXHIBIT 6-2. ACTUAL AND PROJECTED VMT BY VEHICLE CLASS FROM ANNUAL ENERGY OUTLOOK AND COMPARISON WITH FIRST PROSPECTIVE VMT

	National Annual Vehicle Miles Traveled (billion miles per year)			
Vehicle Class	**1990**	**2000**	**2010**	**2020**
LDVs less than 8,500 pounds		2,355	3,017	3,680
Commercial Light Trucks		69	78	96
Freight Trucks greater than 10,000 pounds		207	268	336
Totals	**1,989**	**2,631**	**3,363**	**4,112**
First Prospective VMT estimates	1,642	2,034	2,449	N/A

SOURCES: The Benefits and Costs of the Clean Air Act: 1990 to 2010, EPA Report to Congress, EPA-410-R-99-001, November 1999, Appendix A, pages A-29 to A-31; DOE, 2005; DOE 2003.

EXHIBIT 6-3. DISTRIBUTION OF DOE VMT TO MOBILE6 VEHICLE CATEGORIES

DOE Vehicle Type	MOBILE6 Vehicle Type	2000 MOBILE 6 Default VMT Fraction	2000 VMT Fraction by DOE Vehicle Type	2000 Allocated DOE VMT	2010 MOBILE 6 Default VMT Fraction	2010 VMT Fraction by DOE Vehicle Type	2010 Allocated DOE VMT	2020 MOBILE 6 Default VMT Fraction	2020 VMT Fraction by DOE Vehicle Type	2020 Allocated DOE VMT
LDVs	LDGV	0.484060	0.548795	1,292.41	0.347807	0.396094	1,195.02	0.278784	0.318275	1,171.25
	LDGT1	0.066848	0.075788	178.48	0.089850	0.102324	308.71	0.101366	0.115725	425.87
	LDGT2	0.222534	0.252294	594.15	0.299110	0.340636	1,027.70	0.337444	0.385245	1,417.70
	LDGT3	0.068224	0.077348	182.15	0.091532	0.104240	314.49	0.103245	0.117870	433.76
	LDGT4	0.031374	0.035570	83.77	0.042091	0.047935	144.62	0.047479	0.054205	199.47
	LDDV	0.001107	0.001255	2.96	0.000309	0.000352	1.06	0.000251	0.000287	1.06
	LDDT12	0.000264	0.000299	0.70	0.000009	0.000010	0.03	0.000000	0.000000	0.00
	LDDT34	0.001362	0.001544	3.64	0.001946	0.002216	6.69	0.002217	0.002531	9.31
	MC	0.006268	0.007106	16.73	0.005438	0.006193	18.68	0.005135	0.005862	21.57
Commercial Light Trucks	HDGV2B	0.028740	0.751451	51.85	0.030066	0.767460	59.86	0.030784	0.772458	74.16
	HDDV2B	0.009506	0.248549	17.15	0.009110	0.232540	18.14	0.009068	0.227542	21.84
Freight Trucks	HDGV3	0.001025	0.012858	2.66	0.001043	0.012607	3.38	0.001099	0.013048	4.38
	HDGV4	0.000581	0.007288	1.51	0.000350	0.004231	1.13	0.000306	0.003633	1.22
	HDGV5	0.001201	0.015066	3.12	0.001069	0.012921	3.46	0.001047	0.012431	4.18
	HDGV6	0.002582	0.032390	6.70	0.002288	0.027656	7.41	0.002258	0.026809	9.01
	HDGV7	0.001231	0.015443	3.20	0.000952	0.011507	3.08	0.000924	0.010970	3.69
	HDGV8A	0.000005	0.000063	0.01	0.000003	0.000036	0.01	0.000003	0.000036	0.01
	HDGV8B	0.000000	0.000000	0.00	0.000000	0.000000	0.00	0.000000	0.000000	0.00
	HDDV3	0.002798	0.035100	7.27	0.002805	0.033905	9.09	0.002831	0.033612	11.29
	HDDV4	0.002321	0.029116	6.03	0.002848	0.034424	9.23	0.003000	0.035618	11.97
	HDDV5	0.001009	0.012658	2.62	0.001337	0.016161	4.33	0.001444	0.017144	5.76
	HDDV6	0.005757	0.072220	14.95	0.006509	0.078676	21.09	0.006707	0.079631	26.76
	HDDV7	0.008666	0.108712	22.50	0.009397	0.113584	30.44	0.009607	0.114062	38.32
	HDDV8A	0.010881	0.136499	28.26	0.011212	0.135522	36.32	0.011397	0.135315	45.47
	HDDV8B	0.038808	0.486834	100.77	0.039986	0.483320	129.53	0.040622	0.482298	162.05
	HDGB	0.000583	0.007314	1.51	0.000165	0.001994	0.53	0.000083	0.000985	0.33
	HDDBT	0.000927	0.011629	2.41	0.000953	0.011519	3.09	0.000970	0.011517	3.87
	HDDBS	0.001340	0.016810	3.48	0.001815	0.021938	5.88	0.001928	0.022891	7.69

In addition to different growth rates by vehicle class, the VMT growth factors also account for differences in population growth in different areas of the country, relative to the overall U.S. population growth rates. The following equation illustrates our approach to calculating VMT growth factors for the 2010 and 2020 projection years.

*VMTGF(cy,py,vc) = (VMTNAT(py,vc)/VMTNAT(2000,vc)) * (POP(cy,py)/POP(cy,2000)) / (USPOP(py)/USPOP(2000))*

where:

VMTGF(cy,py,vc)	=	county-specific projection year VMT growth factor by vehicle class
VMTNAT(py,vc)	=	National VMT for projection year by vehicle class (from Exhibit 6-3)
VMTNAT(2000,vc)	=	National VMT for 2000 by vehicle class (from Exhibit 6-3)
POP(cy,py)	=	county-specific projection year population
POP(cy,2000)	=	county-specific population for 2000
USPOP(py)	=	U.S. population total for projection year
USPOP(2000)	=	U.S. population total for 2000

The resulting growth factors by county and MOBILE6 vehicle type were then multiplied by the corresponding VMT records in the 2000 VMT database. Detailed VMT data used can be found in Appendix L.

1990 EMISSIONS ESTIMATES

The 1990 on-road vehicle emission estimates used for the Second Section 812 Prospective Analysis are those developed for EPA for a re-analysis of the 1990 NEI estimates (Pechan, 2004b), with one basic modification to VMT for some States.[47] The 1990 NEI VMT estimates are based on Federal Highway Administration VMT data summaries by State and functional road class, along with VMT estimates for urban areas within each State by functional road class. Two procedures were performed to convert this VMT data into a county/SCC-level format. First, each State's rural, small urban, and large urban VMT by functional roadway class were distributed to the county level based on population data. Second, the resulting county/functional roadway class VMT were allocated to the MOBILE6.2 vehicle classes. The resulting VMT estimates are county-level estimates disaggregated by vehicle type and roadway class.

[47] Full documentation of the 1990 NEI on-road emission inventory can be found at ftp://ftp.epa.gov/EmisInventory/prelim2002nei/mobile/onroad/documentation/nei_onroad_jan04.pdf.

To provide greater consistency with the more recent data used in the projection years, in this analysis the 1990 NEI VMT data were replaced for States or counties with State or locally provided VMT data in the 1999 NEI.[48] For these States or counties, adjusted 1990 VMT data were calculated by multiplying the 1990 NEI VMT by the ratio of the State-supplied VMT contained in the 1999 NEI Version 3 to the FHWA-based 1999 VMT, calculated in the same manner as the 1990 NEI VMT.

This 1990 emission inventory was developed at the county level of detail by month for temperature conditions, fuel parameters, and control programs in place in 1990. EPA's MOBILE6.2 model was used to generate 1990 on-road vehicle emission factors for all States by county groupings, roadway type, and month. The 1990 MOBILE6.2 emission factors were generated using historical State-level monthly minimum and maximum daily temperatures, gasoline volatility (RVP) data, and I/M program information. The 1990 emission estimates were calculated by applying these emission factors to the VMT estimates. Emissions estimates are calculated at the county/vehicle type/roadway type level of detail.

CONTROL SCENARIO ASSUMPTIONS

2000 EMISSION ESTIMATES

Onroad emission estimates for 2000 were calculated for a *without-CAAA* scenario and a *with-CAAA* scenario. As with 1990, the 2000 CAAA scenario was based on the 2000 NEI onroad emission inventory. Again, as with 1990, the VMT data for counties with State or locally supplied VMT data in the 1999 NEI Version 3 were first adjusted in the same manner that the 1990 VMT for these counties were adjusted, as discussed above. The MOBILE6 emission factors for the *with-CAAA* scenario included the effects of all CAA control programs including I/M, reformulated gasoline, RVP controls, oxygenated fuel, Tier 1 emission standards, and national LEV emission standards. Actual I/M programs and fuel programs in place in 2000 were modeled in the *with-CAAA* scenario. Also, States in the Northeast were modeled with the appropriate National LEV program inputs. The MOBILE6.2 defaults were used to account for all national CAA and CAAA emission programs, including Tier 1 emission standards. For the *without-CAAA* scenario, the MOBILE6 command "NO CAA" was used to turn off the effects of the CAAA control measures. The "NO CAA" command in MOBILE6.2 turns off all of the effects of the motor vehicle provisions of the 1990 CAAA authorized regulation, but leaves in place those regulations in place prior to 1990. In addition, emission factors in the *without-CAAA* scenario were modeled with I/M programs present in 1990 and the RVP levels modeled in 1990.

Temperatures were specific to 2000 historical conditions, again at the State and monthly level. The same speeds modeled in 1990 were used in 2000. These are

[48] Note that the 2002 NEI was not available at the time this portion of the VMT analysis was completed.

discussed in more detail in the first section of this chapter. All remaining optional inputs, such as registration distributions or diesel sales fractions were set to the MOBILE6.2 defaults (i.e., none of the optional inputs were used other than those discussed above for the control programs).

Because California's emission standards differ from those in the rest of the country, data supplied by the ARB were used for that State for the 2000 *with-CAAA* scenario. ARB provided an on-road emission inventory for California with all control measures in place, along with the VMT used in calculating the inventory. Emission factors in this inventory were calculated using California's EMFAC model. These emission estimates have been incorporated into the *with-CAAA* emission scenario. However, only annual emission estimates were provided, so the SMOKE modeling files developed for California only contain annual emission estimates, while the modeling files for all remaining States have monthly emission estimates.[49]

PROJECTION YEAR EMISSION ESTIMATES

Projection year on-road emission inventories were calculated for 2010 and 2020 under a *without-CAAA* scenario and a *with-CAAA* scenario. The same VMT projections were used under both scenarios for a given target year, following the VMT development method described above. MOBILE6.2 was used to calculate the emission factors for each of these scenarios, with the exception of California, under the *with-CAAA* scenarios. California is discussed separately below.

Emission Factors

The emission factors used in the projection years were calculated using MOBILE6.2. The *without-CAAA* emission factors were calculated in the same manner as the 2000 *without-CAAA* emission factors, using 1990 I/M programs and 1990 fuel data. Again, the "NO CAA" command was used in the MOBILE6 input files to turn off the default national CAAA control programs. For the *with-CAAA* scenario, the MOBILE6.2 defaults account for all national CAA emission programs, including Tier 1 emission standards, national LEV, Tier 2 emission standards and gasoline sulfur levels, and heavy-duty emission standards and low sulfur gasoline. Actual I/M programs and fuel programs in place in 2000 were modeled in the *with-CAAA* scenarios. For both projection scenarios in 2010 and 2020, 30-year average temperatures (BOC, 1992) are used. Vehicle speeds are the same for all years and scenarios, using the data from Exhibit 6-1.

Adjustments for California

ARB provided projected on-road emission inventories and the corresponding VMT data for 2000 and 2010 with all control measures in place, again calculated using the EMFAC model. In order to maintain consistent growth assumptions for all States, these emission estimates were adjusted to use the VMT projected as discussed above

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[49] SMOKE is the emissions inventory processing model that is used to pre-process estimates for the purposes of generating air quality modeling input files.

for the State of California. To do this, the CARB emission estimates at the SCC level of detail were multiplied by the ratio of the AEO-based VMT projections to the CARB-provided VMT projections, at the SCC level of detail.

Unlike the *with-CAAA* projected emissions, the *without-CAAA* projected emissions for California were calculated using MOBILE6.2 emission factors, as ARB was unable to provide a No CAA emission scenario for the projection years. Due to the differences in the EMFAC and MOBILE6.2 model assumptions as well as the differences in the inputs to these models, the PM emissions in some cases were greater under the *with-CAAA* scenario. Since these were due to different modeling methods rather than actual emission increases under the CAA, the PM emissions for the California *without-CAAA* results were adjusted to reflect the proportional increment in emissions reduction that would have resulted if we were to rely only on MOBILE. To implement this adjustment, first the MOBILE6-based PM_{10} and $PM_{2.5}$ emissions calculated for California both *with-* and *without CAAA* were totaled by 8 vehicle types, with separate emission totals for exhaust, brake wear, and tire wear. The ratio of the *without-CAAA* emissions to the *with-CAAA* emissions by vehicle type and emission component was then calculated, to provide an increment in emissions that was not possible to estimate using EMFAC alone. These ratios were then applied to the California-based *with-CAAA* PM_{10} and $PM_{2.5}$ emissions to estimate a revised set of *without-CAAA* emissions of PM_{10} and $PM_{2.5}$ for California.

EMISSION SUMMARY BY SCENARIO

Exhibit 6-4 summarizes the on-road vehicle emissions in 1990 and in 2000, 2010, and 2020 with and without the effects of the CAAA. Emissions are shown by pollutant and vehicle category. In all cases, with the exception of ammonia, the total on-road emissions in the 2020 *with-CAAA* case, with CAAA authorized control measures in place, are below the 1990 emission levels, despite significant increases in VMT during this time period. In contrast, the 2020 *without-CAAA* emissions are greater than the 1990 total on-road emissions for NO_x, SO_2, and NH_3, and only modest emission decreases, attributable to pre-1990 provisions, occur for VOC, CO, PM_{10}, and $PM_{2.5}$.

For VOC, CO, and NO_x, the emissions from 1990 to each of the *with-CAAA* projection scenarios show steady declines over time, while the emissions in the *without-CAAA* projections initially decrease from 1990 levels, but then begin to increase. Several control programs in place in 1990 account for these initial declines including the Federal Motor Vehicle Control Program, Phase I RVP requirements, and I/M programs already in place in 1990. By 2000, several CAAA programs begin to reduce on-road emissions. These include: Phase II RVP requirements, the Tier 1 emission standards, evaporative control requirements, Federal reformulated gasoline, oxygenated gasoline, more stringent I/M requirements, and California LEV standards in California. After 2000, the national LEV emission standards, Phase II of the Federal reformulated gasoline program, local low RVP gasoline programs, the Tier 2 emission standards, low sulfur gasoline, heavy-duty vehicle emission standards, and low sulfur diesel fuel all contribute to lowering emissions.

The specific requirements of these various programs have an impact on when emissions will be reduced and from what vehicle types. For example, emission standards require time for fleet turnover to occur before significant effects from these requirements can be realized, whereas fuel programs bring immediate emission reductions once the new fuel is in place.

Exhibit 6-4 shows a decrease in NO_x emissions from HDDVs from 2000 to 2010 in the *with-CAAA* scenarios of 48 percent. NO_x emissions from these vehicles are reduced by an additional 68 percent from 2010 to 2020. The initial NO_x reductions are primarily due to the implementation of the earlier HDV emission standards, while the reductions from 2010 to 2020 are more a result of the HDV emission standards and low sulfur diesel fuel that are implemented starting in 2007. For comparison, light-duty gas vehicle (LDGV) NO_x emissions decrease by 63 percent from 2000 to 2010 and decrease an additional 61 percent from 2010 to 2020 with the effects of the CAA. The LDGV NO_x emissions are significantly affected by the Tier 2 NO_x emission standards and low sulfur gasoline, both of which began implementation in 2004. The effects of the Tier 2 emission standards continue to reduce NO_x emissions from 2010 to 2020 as more Tier 2 vehicles are purchased, replacing older, more-polluting vehicles. Reduction in LDGV VMT over this time period also contributes to the NO_x emission reductions. By examining the percentage reduction in a given year from the *without-CAAA* scenario to the *with-CAAA* scenario, the effects of VMT changes can be isolated, because the same VMT projections were used for both scenarios in a given target year. In 2010, we estimate LDGV NO_x emissions are 64 percent less and HDDV emissions are 47 percent less due to the CAAA. In 2020, NO_x emissions from both of these vehicle categories are 85 percent less due to the CAAA programs in place.

Reductions in SO_2 emissions are the direct result of changes in fuel sulfur content. Thus, when CAAA regulations affect the sulfur levels of gasoline or diesel fuel, an immediate corresponding decrease in SO_2 emissions occurs. However, as VMT increases, SO_2 emissions begin to increase again. Nonetheless, the *with-CAAA* SO_2 emissions in 2020 are 93 percent lower than the 1990 on-road SO_2 emissions and 94 percent lower than the *without-CAAA* SO_2 emissions in 2020.

NH_3 emissions show minimal changes in response to the CAAA control programs. In fact, NH_3 emission rates are lower on vehicles without catalysts than those with catalysts. This fact, in combination with increasing VMT, accounts for the significant increases in NH_3 emissions from 1990 to 2000 (*with-* or *without-CAAA*) as non-catalyst vehicles are phased out.

Exhibit 6-5 displays the onroad vehicle sector *with-* and *without-CAAA* emission summaries by pollutant in a graphic format.

EXHIBIT 6-4. NATIONAL ONROAD VEHICLE EMISSIONS BY VEHICLE TYPE* (TPY)

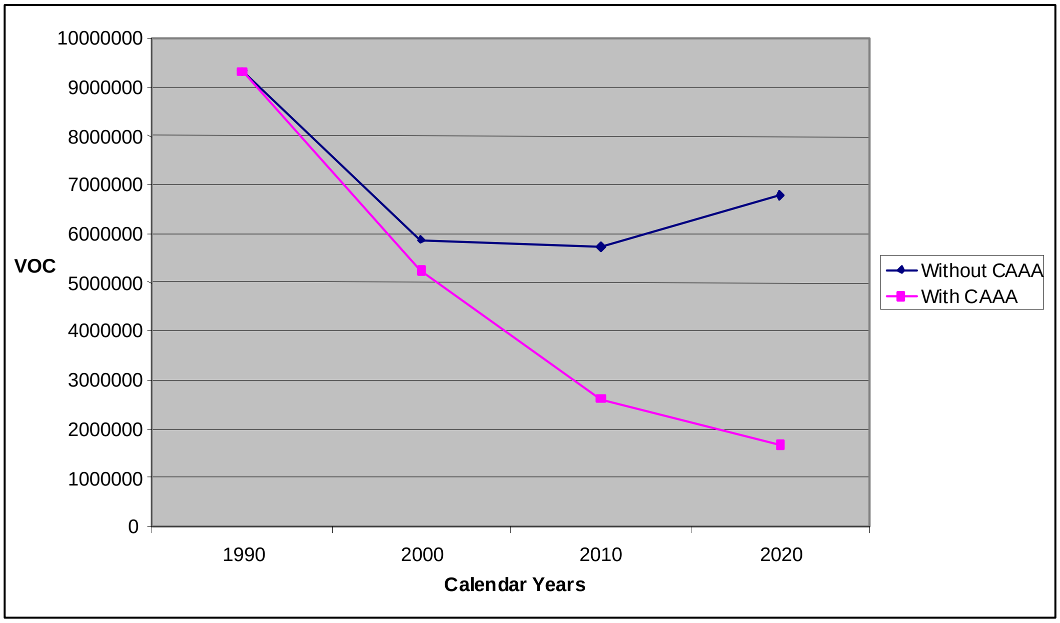
Vehicle Type	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
VOC							
LDGV	5,606,477	3,211,214	2,869,586	2,506,018	1,029,969	2,478,590	483,884
LDGT1	1,547,385	1,409,353	1,229,018	1,975,235	822,159	2,694,542	624,092
LDGT2	1,053,084	709,179	655,476	816,237	477,329	1,089,319	345,039
HDGV	629,345	262,649	241,589	174,131	108,391	207,762	63,153
LDDV	17,671	4,602	4,491	925	360	924	124
LDDT	14,958	6,491	6,196	7,344	3,165	10,407	2,004
HDDV	412,785	245,200	214,815	226,901	144,345	271,504	120,538
MC	45,955	24,295	24,585	27,222	28,289	31,490	31,782
Total	9,327,660	5,872,983	5,245,756	5,734,012	2,614,007	6,784,539	1,670,617
NO_X							
LDGV	4,215,615	2,737,163	2,291,082	2,309,526	839,101	2,272,760	331,188
LDGT1	956,202	1,119,246	982,685	1,855,108	812,991	2,585,697	507,084
LDGT2	538,827	442,728	422,583	658,901	437,306	920,341	325,875
HDGV	564,006	440,794	431,095	446,893	220,028	540,431	81,067
LDDV	42,513	9,462	9,354	2,280	1,134	2,279	496
LDDT	22,397	10,260	9,933	13,335	8,540	18,721	8,139
HDDV	3,174,678	4,007,535	3,912,552	3,803,221	2,013,609	4,335,983	643,291
MC	21,757	14,921	14,454	16,655	16,352	19,208	18,702
Total	9,535,993	8,782,108	8,073,738	9,105,919	4,349,062	10,695,419	1,915,842
CO							
LDGV	66,548,696	42,635,956	36,159,393	34,299,363	18,394,463	33,861,137	13,124,394
LDGT1	19,616,735	21,536,217	17,810,223	31,585,003	15,218,908	42,866,174	14,894,501
LDGT2	12,411,894	9,875,050	8,628,313	11,661,901	6,607,649	15,419,371	6,512,334
HDGV	8,867,768	3,497,147	3,242,055	1,491,136	1,303,822	1,721,454	1,234,132
LDDV	38,056	9,897	9,901	2,370	2,000	2,365	1,347
LDDT	24,584	11,452	10,682	13,351	7,240	18,891	7,375
HDDV	1,795,952	1,297,603	1,104,483	1,243,538	644,349	1,434,882	235,625
MC	263,313	173,758	165,816	194,724	209,536	225,271	229,800
Total	109,566,997	79,037,081	67,130,866	80,491,386	42,387,967	95,549,545	36,239,508

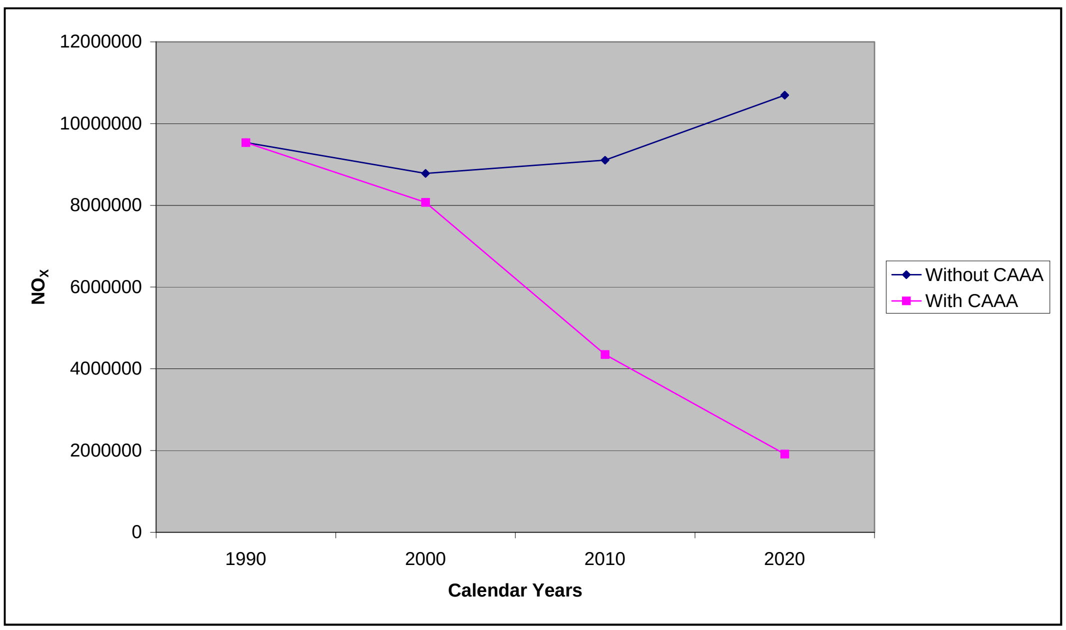
Vehicle Type	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
SO_2							
LDGV	109,946	120,040	102,272	110,039	10,408	107,854	10,176
LDGT1	30,851	58,498	46,288	103,303	9,677	143,310	13,424
LDGT2	20,671	25,864	22,471	44,852	4,274	62,401	5,917
HDGV	16,280	15,264	13,253	16,245	1,517	19,734	1,839
LDDV	12,146	2,454	384	762	4	760	4
LDDT	5,081	4,205	698	6,934	34	9,846	48
HDDV	304,522	406,074	67,905	514,799	4,002	642,501	5,005
MC	567	368	321	411	38	475	44
Total	500,064	632,766	253,592	797,345	29,954	986,882	36,457
PM_{10}							
LDGV	56,446	52,175	50,887	47,882	41,714	46,838	40,827
LDGT1	16,958	21,837	21,187	39,470	31,679	55,238	43,947
LDGT2	13,961	9,413	9,211	13,143	10,617	18,216	14,508
HDGV	16,781	9,730	9,643	8,358	5,645	10,256	4,216
LDDV	10,525	1,700	1,593	193	148	146	74
LDDT	4,570	1,668	1,481	877	585	773	359
HDDV	264,829	150,105	126,425	118,860	63,379	136,739	31,116
MC	662	429	427	462	448	528	513
Total	384,733	247,056	220,854	229,246	154,216	268,733	135,559
$PM_{2.5}$							
LDGV	34,460	28,312	27,014	25,846	19,685	25,294	19,273
LDGT1	11,264	12,446	11,798	23,383	15,571	33,004	21,694
LDGT2	9,327	5,665	5,463	7,820	5,264	10,848	7,146
HDGV	11,207	7,035	6,949	6,440	3,853	8,106	2,434
LDDV	9,448	1,512	1,405	156	113	61	29
LDDT	4,122	1,484	1,297	695	429	653	233
HDDV	241,647	135,026	111,347	105,085	51,189	120,890	19,808
MC	377	244	242	266	252	297	282
Total	321,852	191,723	165,515	169,690	96,356	199,153	70,899

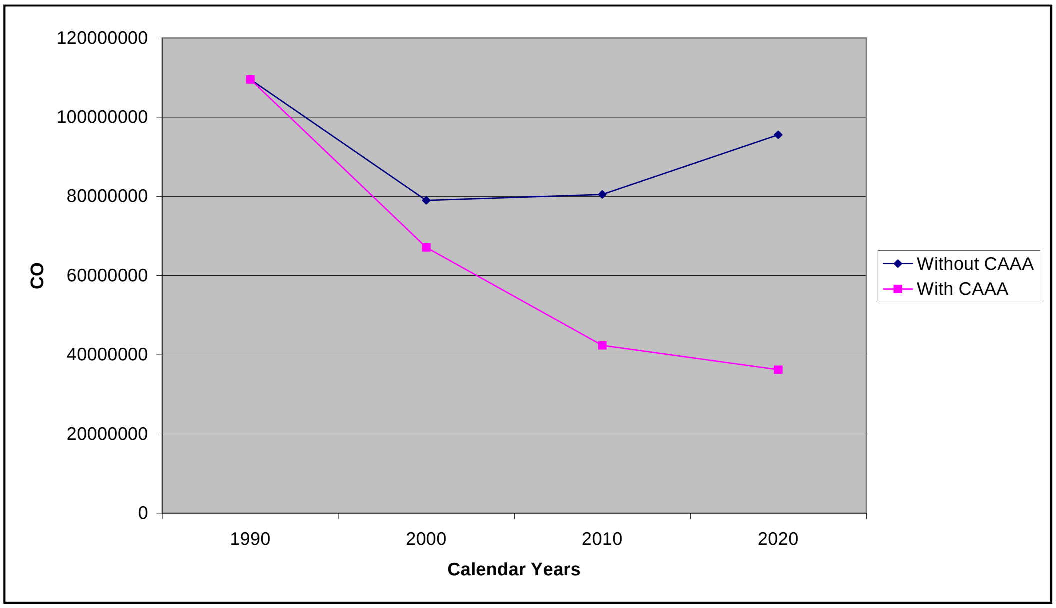
Vehicle Type	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
NH_3							
LDGV	115,100	175,817	175,722	165,082	163,695	161,755	159,947
LDGT1	21,435	66,000	65,989	119,239	118,961	165,416	164,925
LDGT2	9,439	20,688	20,688	39,428	39,428	55,095	55,095
HDGV	3,692	3,868	3,868	4,343	4,343	5,344	5,344
LDDV	169	36	36	13	13	13	13
LDDT	60	39	39	63	63	89	89
HDDV	4,012	5,994	5,994	7,774	7,774	9,743	9,743
MC	196	127	127	142	142	164	164
Total	154,103	272,569	272,464	336,083	334,417	397,618	395,319

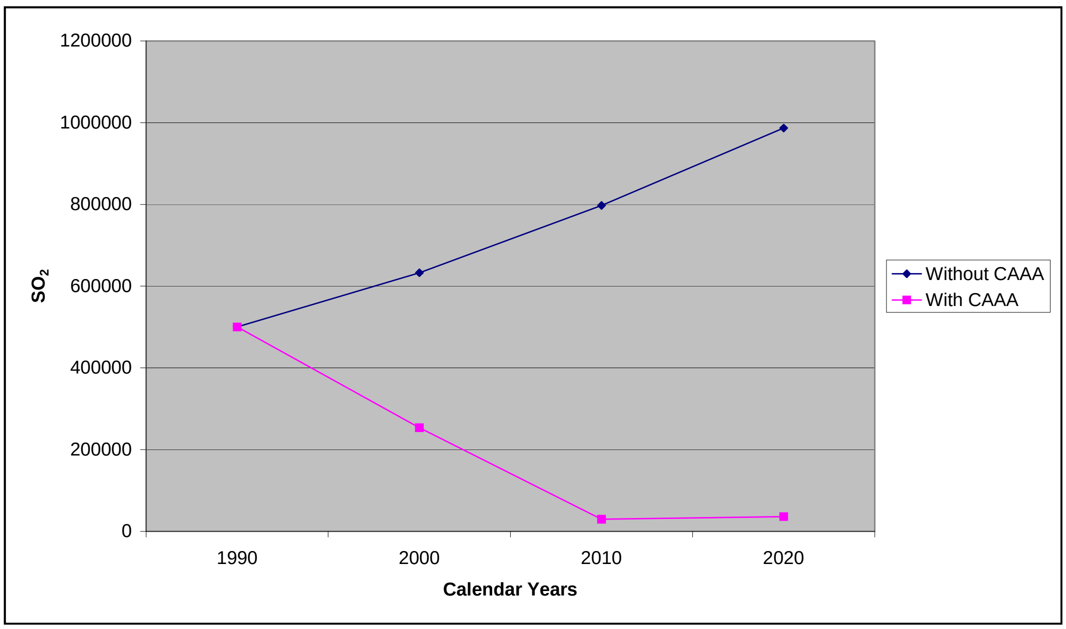
NOTE: *The totals reflect emissions for the 48 contiguous States, excluding Alaska and Hawaii. Totals may not add due to rounding.

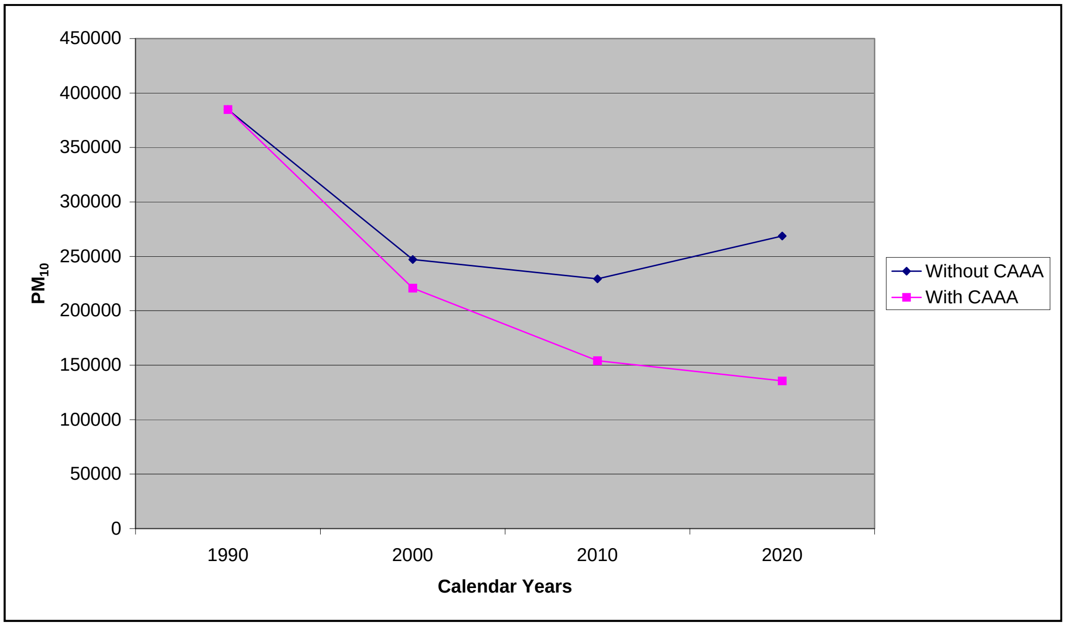
EXHIBIT 6-5. *WITH-* AND *WITHOUT-CAAA* SCENARIO ONROAD VEHICLE EMISSION SUMMARIES BY POLLUTANT

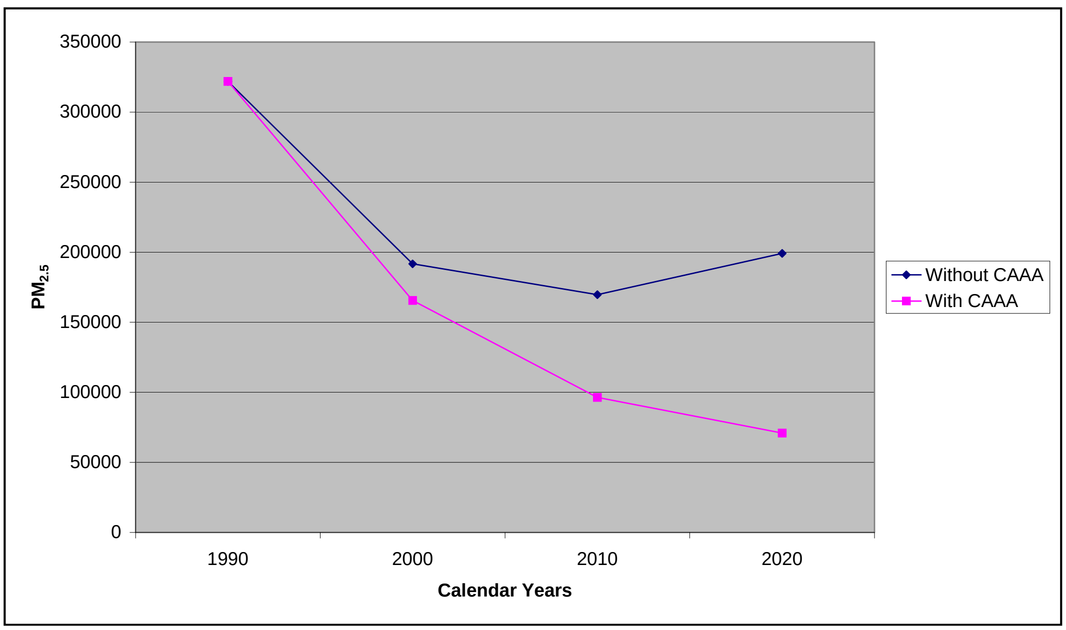


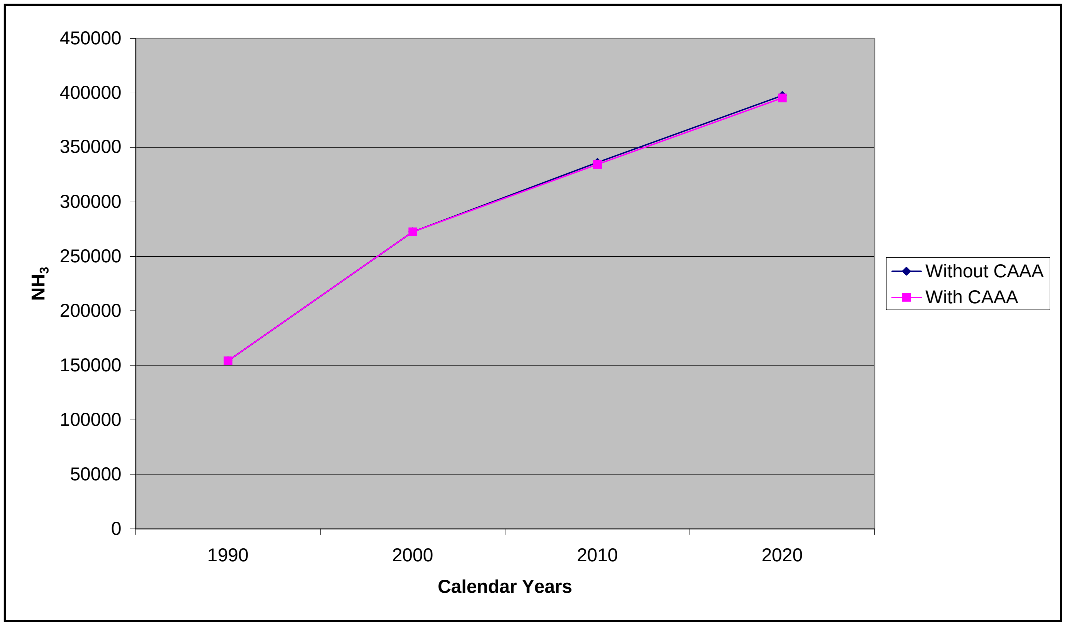



120000000
100000000
80000000
60000000
40000000
20000000
0
CO
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


1200000
1000000
800000
600000
400000
200000
0
SO_2
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


450000
400000
350000
300000
250000
200000
150000
100000
50000
0
PM10
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


350000
300000
250000
200000
150000
100000
50000
0
PM2.5
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA

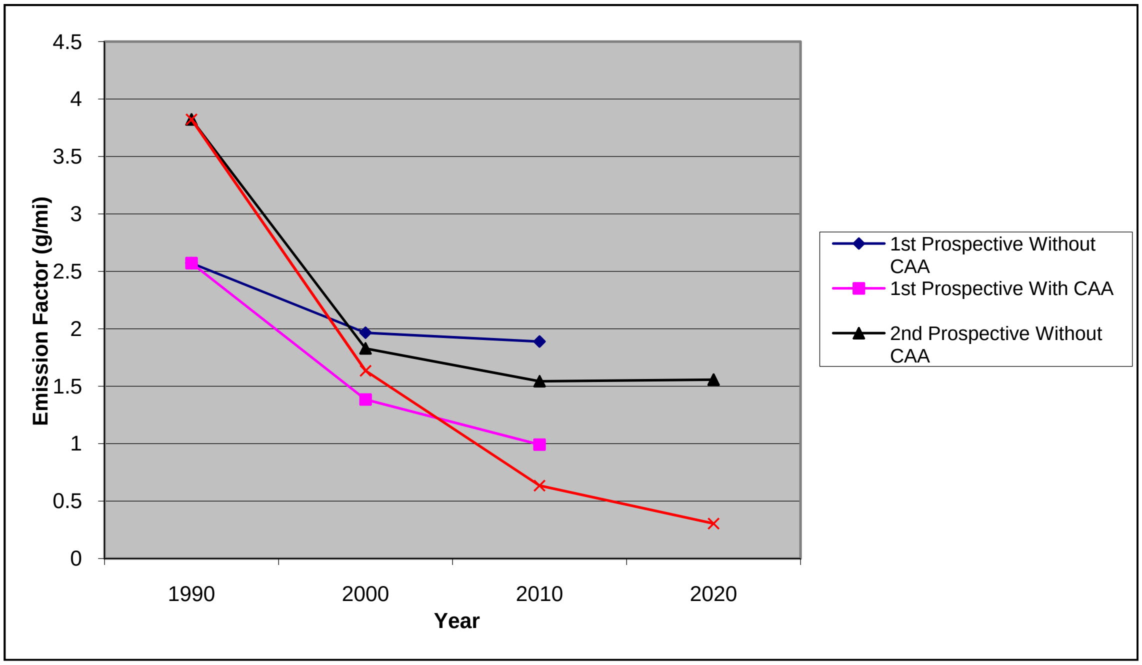


ASSESSMENT OF DIFFERENCES IN YEAR 2000 ESTIMATES ACROSS STUDIES

When comparing the Exhibit 6-4 onroad emissions from the 2000 *with-CAAA* scenario to the corresponding emissions from the 2000 *without-CAAA* scenarios, only very minimal emission differences are observed in 2000 for VOC, CO, and NO_x. In contrast, similar comparisons using data from the first Section 812 Prospective Analysis showed much larger decreases from the *without-CAAA* to the *with-CAAA* scenarios in 2000. Several analyses were undertaken to determine if these emission calculations were correct, and if so, to determine what was causing the *with-CAAA* and *without-CAAA* emissions difference to be so small in 2000.

The initial step in this analysis involved comparing *equivalent emission factors* from the two analyses. The term *equivalent emission factors* represents the total national emissions from a given pollutant and vehicle type divided by the corresponding national VMT. Exhibit 6-5 illustrates the VOC *equivalent emission factors* for LDGVs from the first and second Section 812 Prospective Analyses. This figure clearly shows that a much greater reduction in VOC emissions was estimated in 2000 from the *without-CAAA* scenario to the *with-CAAA* scenario in the first prospective analysis than in the second. Note that the VMT estimates used in the first Prospective analysis are about 30 percent lower than the national VMT estimates in calendar year 2000 used in this study. However, this evaluation focuses on the relative differences between *with-* and *without-CAAA* estimates for each of the two Prospective studies rather than the magnitudes of their emission estimates.

EXHIBIT 6-6. VOC LDGV EQUIVALENT EMISSION FACTORS FOR SECTION 812



The next step involved generating test runs of MOBILE6 to verify that the direct output of MOBILE6 agreed with these results. MOBILE6 inputs were generated for a single scenario. The inputs for the *without-CAAA* case were identical to those for the *with-CAAA* case, with the exception that the NO CLEAN AIR ACT command was turned on in the *without-CAAA* case. The resultant emission factors were in agreement with the equivalent emission factors shown in Exhibit 6-6. Next, the input files were modified to generate by-model-year emission factors. In reviewing the by-model-year emission factors, it was observed that the exhaust running emission factors for some model years were actually *lower* in the *without-CAAA* case than in the *with-CAAA* case. In the case of VOC exhaust emissions for LDGVs, this occurs beginning with the 1994 model year. In the example tested, in model year 2000, the *with-CAAA* emission factor was 47 percent *greater than* the *without-CAAA* emission factors.

EPA's Office of Transportation and Air Quality (OTAQ) provided some guidance in understanding and interpreting these results. The primary cause of these seemingly anomalous results is that MOBILE6 predicts that Tier 1 vehicles (those beginning to be phased in starting in 1994) and LEV vehicles that are exposed to high gasoline sulfur levels (as in the *without-CAAA* case in the calendar year 2000 run) will have exhaust running emission factors greater than Tier 0 vehicles both when new, and as they age. In other words, MOBILE6 assumes that Tier 0 vehicles tolerate high sulfur gasoline better than Tier 1 vehicles and thus retain more of their emission control capability. This MOBILE6 estimate was based on the fuel analysis done for the Tier

2 rule that justified the lowering of the allowed sulfur content of gasoline (EPA, 2001) beginning in calendar year 2004. Tier 1 and LEV exhaust running emission factors become significantly lower than those for Tier 0 vehicles once low sulfur gasolines are used. Since gasoline sulfur does not affect evaporative emissions, the net effect on inventories is still a benefit for the CAAA. However, it is just smaller than the effect that had been predicted by MOBILE5 (as seen in the first Section 812 Prospective analysis). The test results shown in EPA's analysis of the short-term effects of fuel sulfur on Tier 0, Tier 1, and LEV vehicles do correspond reasonably well with the test results obtained from MOBILE6. The increasing disbenefit of the CAAA from 1994 to 2000, seen in the by-model-year running exhaust emission factors output by MOBILE6, is caused by the increasing penetration of Tier 1 vehicles.

EPA's analysis also includes long-term sulfur effects and irreversibility effects of sulfur. However, these effects should not be of concern for the 2000 analysis. From the documentation (EPA, 2001), the long-term sulfur effects were only applied to LEV and cleaner vehicles. In 2000, these vehicles would only have been in place in the Northeast (and CA) and only a portion of the 1999 and 2000 vehicles there would have met the LEV standards. The irreversibility effects would have only been applied to 2004 and later vehicles, so this is not a concern.

CHAPTER 7 | NONPOINT SOURCES

OVERVIEW OF APPROACH

Nonpoint sources include a wide range of emissions categories, which are handled similarly because of the common characteristic that they are relatively diffuse sources where we have no ready means to ascribe the emissions to a single well-defined geographic point (or stack). They include fuel combustion, agricultural, solvent utilization, gasoline refueling station, locomotive, and aircraft emissions, to name just a few.

The basic approach for estimating the effect of air pollution control programs on nonpoint source categories included identifying the source types whose emissions are expected to be influenced by Federal control programs, estimating how these programs might affect sources differently in different parts of the country, and then capturing the expected effects of State and local area regulations affecting nonpoint source categories. Programs in the national controls category include: Stage II (at the pump) emissions from service stations, residential woodstoves (NSPS), commercial marine vessels emission standards, and locomotive emission standards. Local/regional control programs included in this second group are measures "on-the-books" in 1-hour ozone nonattainment areas for VOC and NO_x control, and adoption of the Ozone Transport Commission model rules in the Northeast and Mid-Atlantic States.

This Chapter describes the core scenario analysis for this category of sources. The core scenario analysis does not include the additional emission reductions that might occur for nonpoint source categories to meet the requirements for the 8-hour ozone or $PM_{2.5}$ NAAQS. Measures to meet these NAAQS requirements are described in Chapter 8. Activity growth factors used in the nonpoint source analysis are described in Chapter 2 of this report.[50]

The chapter first reviews a series of adjustments that were made to update the 1990 emissions estimates to provide a more accurate basis for projection of the *without-CAAA* scenario estimates to 2000, 2010, and 2020. Next, we document several adjustments to the 2002 NEI to provide more accurate estimates of fine particulate matter emissions. We then review the emissions control factor estimates that were

[50] As part of the process of preparing inputs for the air quality modeling and benefits estimation stages of the second prospective analysis, the Project Team applied transport factors to fugitive dust emissions. This step is described in greater detail in Appendix M.

applied for projection years in two parts - national controls, and state/local controls. The chapter concludes with a summary of the emissions results for this sector.

1990 EMISSION ESTIMATES

The 1990 EPA NEI is the primary data source used to estimate 1990 nonpoint source category emissions. Because there have been some significant revisions in the methods used to estimate criteria pollutant emissions since the 1990 NEI was created, the Project Team revised and updated 1990 estimates for the most significant source categories, so that observed differences in emissions among the scenario years would not be affected by artifacts of the methods used in the calculations. Resource limitations precluded the option to re-compute all 1990 nonpoint source emissions using 2002 NEI methods. Instead, 1990 emissions categories were identified using a two-step process. First priority source categories were ranked according to the total emissions estimates for all criteria air pollutants combined. Six priority source categories were identified in this first step. Priority source categories and revised 1990 emission estimation methods for the first step are described below:

1. Prescribed burning and wildfires – the 2002 NEI emission estimates were revised to reflect historical average activity levels. These historical emission levels are also used to represent 1990, 2010, and 2020 emissions.
2. Residential wood combustion – 1990 emissions for wood burning in residential fireplaces and woodstoves reflect 1990 levels of residential wood combustion relative to 2002 levels, and 100 percent use of non-certified residential wood combustion units. Control factors (efficiencies) for 1990 reflect the higher 1990 emission rates for residential wood combustion SCCs compared with the 2002 emission rates used to develop the 2002 NEI.
3. Railroad locomotives (diesel engines) – the 1990 activity levels for this source type were backcast from 1990 levels of railroad diesel consumption relative to 2002 levels. Emission rates in 1990 are also adjusted to reflect higher 1990 emission rates for certain SCCs relative to 2002 emission rates.
4. Agricultural tilling – the 1990 activity relative to 2002 accounted for differences in the number of planted acres in that year as well as the lower penetration of conservation tillage relative to conventional tillage.
5. Commercial marine vessels – the 1990 activity for this source type was estimated based on the ratio of 1990 levels of marine vessel distillate fuel consumption relative to 2002 levels.
6. Industrial coal combustion – the 1990 activity for this source type reflected 1990 levels of industrial coal consumption relative to 2002 levels.

In the second step, we identified and prepared new estimates for 1990 for source categories which had underrepresented ammonia emissions in the 1990 NEI. In some cases, these were categories with 0 emissions in 1990 but nonzero emissions in 2002. In other cases, these were categories where the trend in ammonia emissions was counterintuitive according to the judgment of the Project Team; for example, a steep upward trend between 1990 and 2002 for a category where activity did not increase at the same rate and there is no immediate reason to suggest emission rates changed substantially. These instances are described below:

1. Agricultural field burning emission estimates for 1990 were computed using 2002 NEI emission estimates for this source category backcast to 1990 using the ratio of 1990 agricultural crop production and 2002 agricultural crop production.

2. Open burning of land clearing debris emission estimates for 1990 were computed using 2002 NEI emission estimates for this source category backcast to 1990 using the ratio of 1990 population and 2002 population.

3. Domestic animal and wild animal waste emission estimates for 1990 were computed using 2002 NEI emission estimates for this source category backcast to 1990 using the ratio of 1990 to 2002 animal population estimates.

4. Agricultural crop fertilizer emission estimates for 1990 were computed using 2002 NEI emission estimates for this source category backcast to 1990 using the ratio of 1990 to 2002 crop production (as the indicator for anhydrous ammonia and diammonium phosphate use) or fertilizer application-urea (as the indicator for urea).

5. Prescribed burning of rangeland emissions estimates for 1990 were estimated to be equal to those in the 2002 NEI.

6. For certain additional miscellaneous source categories with positive NH_3 emissions in the 2002 NEI, but zero NH_3 emissions in the 1990 NEI, the 1990 NH_3 emissions were set equal to the 2002 NH3 emissions.

Note that, in all instances where 1990 emissions categories were identified and updated, all of the criteria pollutant emissions from that source category were updated using the procedure stated above. In all other cases, for all other pollutants and source categories not listed above, the 1990 NEI nonpoint source emission inventory was used to estimate 1990 air pollutant emissions for this sector.

One additional modification was made to the 1990 NEI, to account for likely underestimation of PM emissions and to ensure consistency in PM methods for the with- and *without-CAAA* scenarios. PM emissions in the 1990 NEI point and area source inventories are for filterable emissions only. Beginning with Version 3 of the final 1999 National Emission Inventory point and area source files, however, EPA began adding condensable PM emissions associated with fuel combustion sources to the inventories. As a result, the 2002 NEI includes both filterable and condensable PM emissions. The Project Team therefore augmented the 1990 PM emissions for point and area source inventories to add condensable PM emissions. The specific procedures to complete the PM augmentation are described in detail in Appendix J of this report. In addition, Appendix J documents methods applied to resolve some quality assurance issues identified for non-fuel combustion source filterable emissions in the 1990 area source Section 812 inventory.

The above adjustments notwithstanding, the Project Team determined that the 1990 NEI did not accurately measure $PM_{2.5}$ emissions from both area and non-EGU point sources, as noted in Chapter 3. Specifically, the emissions estimation procedures in the 1990 NEI led to a substantial overestimation of emissions from several source categories, including construction, paved and unpaved roads, residential wood burning, and industrial combustion. For these five source categories, the Project Team recalculated *without-CAAA* emissions for 2000 using methods consistent with those used in the 2002 NEI. The Project Team then applied standardized growth factors to the 2000 $PM_{2.5}$ emissions to generate *without-CAAA* emissions estimates for 2010 and 2020 for these source categories. A final adjustment was made to correct underestimation of $PM_{2.5}$ emissions for SCCs for which estimation methods had not yet been developed in the 1990 NEI. For all such SCCs, the Project Team set *without-CAAA* emissions to be equal to *with-CAAA* emissions in each target year.

SPATIAL RESOLUTION OF AMMONIA INVENTORIES FOR ANIMAL HUSBANDRY

Most state, tribal and local area emission inventories include ammonia emissions from animal husbandry in their nonpoint source (area source) emission inventory. Therefore, the emissions from these activities are estimated by county. In the emissions modeling step, these emissions are allocated to grids using spatial surrogates. Because of the size and location of some of these animal husbandry operations, there is interest in including these emissions in point source emission inventories. While most areas still report their ammonia emissions from animal husbandry in the nonpoint source inventory, there are states that have submitted point source emission records with animal husbandry emissions for the 2002 NEI. For example, Minnesota has ammonia emissions for these categories (beef cattle feedlots) in their 2002 point source emission files. For our purposes, we have characterized animal husbandry ammonia emissions as an area source except in those few cases where states reported a point source location in their 2002 NEI submission.

2000 EMISSION ESTIMATES

Year 2000 *with-CAAA* criteria pollutant emissions for nonpoint sources are estimated using the EPA 2002 NEI final nonpoint source file. For this section 812 project, the Project Team added missing $PM_{2.5}$ primary emissions to the final 2002 nonpoint NEI that EPA delivered to the Project Team on January 6, 2006. This database augmentation was performed for source categories and counties for which the State or local agency provided PM_{10} primary emissions, but no corresponding $PM_{2.5}$ emissions. For this project, ratios were applied to the PM_{10} primary emissions to estimate $PM_{2.5}$ primary emissions. These ratios varied from 0.1 to 1.0 depending on the source category. The 0.1 ratio is applied to fugitive dust categories. Information about the derivation of these ratios and assignment to relevant source categories can be found on the EPA website, Technology Transfer Network, Clearinghouse for Inventories and Emission Factors (http://www.epa.gov/ttn/chief/net/2002inventory.html).

CONTROL SCENARIO ASSUMPTIONS

NATIONAL CONTROLS

This section describes how the future effects of Federal control programs on nonpoint source sector emissions were estimated.

Locomotives

Emission reduction impacts of the Federal locomotive engine standards are estimated in an EPA Regulatory Support Document (EPA, 1998). This document contains emission reduction information specific to Class I Operations, Class II/III Operations, Passenger Trains (Amtrak and Commuter Lines), and Switch (Yard) Locomotives. Year-specific percentage reduction estimates for selected pollutants are available for each locomotive sector for each year between 1999 and 2040. These emission reductions reflect the control technology efficiencies, as well as the expected rule penetration for the years of interest. Rule effectiveness was assumed to be 100 percent.

In addition, overall SO_2, PM_{10}, and $PM_{2.5}$ emission reductions associated with decreases in the diesel fuel sulfur content were also included. These were estimated from future base case and control case locomotive emission inventories prepared for EPA's regulatory impact analysis for the Clean Air Diesel Rule (EPA, 2004d). In the case of PM, since exhaust PM standards already apply to locomotives, a combined emission reduction was calculated for each future year that accounted for both the exhaust standards and reductions in PM sulfate due to the fuel sulfur limits.

Commercial Marine Vessels

EPA has promulgated two sets of commercial marine vessel regulations: a regulation setting Category 1 and 2 marine diesel engine standards, and a regulation setting Category 3 marine diesel engine standards. Category 1 marine diesel engines are defined as engines of greater than 37 kilowatts, but with a per-cylinder displacement of 5 liters/cylinder or less. Category 2 marine diesel engines cover engines of 5 to 30 liters/cylinder, and Category 3 marine diesel engines include the remaining, very large, engines. For this analysis, overall emission reductions were estimated for each projection year of interest using information from the regulatory support documents prepared for these rulemakings (EPA, 1999; EPA, 2003). In addition to the EPA standards, beginning in 2000, marine diesel engines greater than or equal to 130 kilowatts are subject to an international NO_x emissions treaty (MARPOL) developed by the International Maritime Organization. The emission reductions reflect both the MARPOL and EPA standards.

Because the reductions vary by category of vessel, assumptions were made concerning the characterization of engines associated with diesel commercial marine vessel SCCs included in the base year inventory. For SCC 2280002100 (Marine Vessels, Commercial Diesel Port emissions), Category 2 engines were assumed. For SCC 2280002200 (Marine Vessels, Commercial Diesel Underway emissions), Category 3 engines were assumed.

Similar to locomotives, overall SO_2, PM_{10}, and $PM_{2.5}$ emission reductions associated with decreases in the diesel fuel sulfur content were also included based on information in EPA's regulatory impact analysis for the Clean Air Diesel Rule (EPA, 2004b).

Stage II-Onboard VRS

The control efficiency from refueling onroad vehicles will be greater in 2010 and 2020 than in 2002 due to vehicle turnover and the Federal requirement for onboard vapor recovery system (VRS) in onroad vehicles. Percentage reductions in VOC emissions from this control measure in 2010 and 2020, relative to 2002, were calculated using a sampling of MOBILE6 runs, including the effect of Stage II programs where they are in place. These resulting reduction factors were included in the nonpoint source sector control files.

Residential Wood Combustion

To account for the effect of the replacement of retired wood stoves/inserts that emit at pre- residential wood heater NSPS levels, control factors were developed for 2010 and 2020 by pollutant. These control factors were developed using an annual 2 percent retirement rate for wood stoves/fireplace inserts along with the pre- and post-NSPS wood stove and fireplace emission factors used in the 2002 NEI (EPA, 2005). SCC/year-specific weighted emission factors from the pre- and post-NSPS emission factors and estimates of the proportion of total wood consumption associated with pre- and post-NSPS units were developed for each base and forecast year. Control factors represent the ratio of the forecast year weighted emission factor for a given pollutant to the base year weighted emission factor for that pollutant. SCCs for "controlled" wood stoves and fireplace inserts have no control efficiency applied. Their future year emissions change in proportion to the activity growth rate.

STATE AND LOCAL AREA CONTROL PLANS BY REGION

State and local area-specific control plans affecting nonpoint sources were incorporated in the 2010 and 2020 projections using the information developed by the five RPOs, or information from their respective work plans indicating what the primary regulations are that are influencing nonpoint source emission rates in this period.

MANE-VU

The focus of nonpoint source controls for this Northeast Mid-Atlantic State region is the effect of the OTC model rules on VOC emissions from the various solvent categories that these controls are designed to reduce.

Exhibit 7-1 displays the nonpoint source VOC solvent category post-2002 rule effectiveness, rule penetration, and control efficiency values that were applied in the OTC States to simulate the effects of adoption of the OTC model rules. Future year control efficiencies are contrasted with those expected to have been used in computing 2002 emissions in the OTC States. The values in Exhibit 7-1 are an approximation of what is occurring in these States during this time period because each State has added regulations to achieve such emission reductions according to their own individual schedules. In general, though, the timing of the model rule adoption for consumer products and AIM coatings is expected to occur after 2002, but before 2010 in most OTC States.

EXHIBIT 7-1. OTC STATE MODEL RULE VOC SOLVENT CATEGORY CONTROL INFORMATION

Category	Year	Control Efficiency	Rule Penetration	Rule Effectiveness	Emission Reduction %
Consumer Products	Base (2002)	20	48.6	100	9.7
	Future (all post-2002)	34.2	48.6	100	16.6
AIM Coatings	Base (2002)	20	100	100	20
	Future (all post-2002)	44.8	100	100	44.8

The effects of adopting OTC model rules to reduce autobody refinishing and solvent cleaning (degreasing) emissions are expected to be included in OTCState2002 emission inventories, so no post-2002 control factors are applied to the OTC States for these solvent categories.

Portable fuel container rules are also being adopted in the OTC States, with 2003 assumed as the average rule adoption date in these States. The VOC reduction benefits of portable fuel container rules within the OTC States are based on a 10-year rule penetration period and a 75 percent VOC control efficiency. Some States did not include portable fuel container emissions in their 2002 emission inventories.

To further reduce evaporative VOC emission at service stations, New Jersey has a new requirement that is expected to go from a required 90 percent Stage I VOC control efficiency in 2002 to a 98 percent control efficiency as they adopt ARB-type requirements. This change in Stage I requirements was included in the 2010 and 2020 emission projections.

VISTAS

For the VISTAS emission projections, this region reported that for stationary area sources (nonpoint), no State-supplied growth or control factors were provided (MACTEC, 2005). Thus, for all sources in this sector, growth and controls were applied based on controls initially identified for the CAIR and growth factors identified for the CAIR projections. VISTAS estimated the effect of controls for Stage II-service station emissions using linear interpolations of values developed for the EPA heavy-duty diesel rulemaking effort. Because the Project Team developed a consistent approach for including the joint effects of Stage II control programs and onboard VRS on future year VOC emissions to be applied in this analysis, the VISTAS information was not used for this source category.

LADCO

Auto Body Refinishing/Mobile Equipment Repair and Refinishing (MERR)

For SCC 2401005000, a 29 percent additional VOC control efficiency was applied to all future year emissions in certain Wisconsin counties, where a more stringent than Federal standard MERR regulation applies. Base year 2002 emission estimates include the effects (37 percent VOC emission reduction) of the national VOC emission standards for automobile refinish coatings. With the 37 percent VOC emission reduction included in Wisconsin's base year emission estimates, this Wisconsin rule achieves a 55 percent reduction from uncontrolled VOC in future years. The Wisconsin counties where the auto body refinishing rule applies are: Kenosha, Kewaunee, Manitowoc, Milwaukee, Ozaukee, Racine, Sheboygan, Washington, and Waukesha.

Solvent Cleaning Operations

The LADCO Comparability Study's suggested cold cleaning-auto repair emission factor is 270 pounds of VOC per employee. In Illinois, the Chicago and Metro East areas of the State have a cold cleaning VOC regulation that is equivalent to what is required in the OTC model rule. The emission reduction credit for this regulation is a 66 percent reduction from uncontrolled levels. An equivalent regulation affecting the southern Indiana counties of Clark and Floyd is expected to achieve the same 66 percent VOC reduction. These emission reductions were applied in the following counties:

State	County Name	State	County Name
ILLINOIS	Cook	INDIANA	Clark
	Du Page		Floyd
	Kane		
	Lake		
	McHenry		
	Madison		
	Monroe		
	St. Clair		
	Will		

These control percentages were applied to SCCs 2415345000 (Miscellaneous Manufacturing [SIC code 39]: Cold Cleaning) and 2415360000 (Auto Repair Services [SIC 75]: Cold Cleaning).

Portable Fuel Containers

At the time we developed emissions estimates, a portable fuel container rule was being considered in Illinois that would reduce VOC emissions from SCCs 2501011010 (Residential Portable Fuel Containers) and 2501012010 (Commercial Portable Fuel Containers) in future years. This rule was expected to reduce fuel container VOC emissions by 75 percent from pre-control levels, and turnover from old to new containers was expected to take 10 years. We therefore modeled emissions as if the rule were implemented in 2005 as planned, with rule penetration for existing fuel containers at 5 percent in the summer of 2005, 15 percent in the summer of 2006, 25 percent in the summer of 2007, etc. until 100 percent rule penetration would be achieved by 2015. Illinois ultimately chose not to implement this requirement. However, EPA in 2007 imposed similar requirements under the Mobile Source Air Toxics rule, a rule which was finalized after our cutoff and is therefore not reflected in our emissions inventory. The MSAT rule imposes fuel container requirements that take effect in 2009, four years after we modeled them to first take effect in Illinois. As a result, in Illinois we likely overstate the VOC reductions from this source in target years 2010 and 2020, but in all other states we understate the reductions in those years.

CENRAP

Exhibit 7-2 summarizes the control factors that were developed and applied in the CENRAP States to simulate the effect on future emission rates where regulations are expected to produce post-2002 emission reductions. The subsections below explain how the individual State regulations were evaluated in order to develop the control efficiency values listed in Exhibit 7-2.

EXHIBIT 7-2. CENRAP STATE VOC SOLVENT CONTROLS IN 2010 AND 2020

Counties	Pollutant	Control Efficiency* (%)	SCC	Description
KS: Johnson, Wyandotte	VOC	66	2415000000	Solvent Utilization: Degreasing: All Processes/All Industries
TX: Dallas, El Paso, Galveston, Hardin, Harris, Jefferson, Tarrant	VOC	35	2401005000	Auto Refinishing: SIC 7532
TX: Bastrop, Bexar, Caldwell, Comal, Gregg, Guadalupe, Hays, Nueces, Travis, Victoria, Williamson, Wilson	VOC	83	2415105000	Furniture and Fixtures (SIC 25): Open Top Degreasing
			2415110000	Primary Metal Industries (SIC 33): Open Top Degreasing
			2415120000	Fabricated Metal Products (SIC 34): Open Top Degreasing
			2415125000	Industrial Machinery and Equipment (SIC 35): Open Top Degreasing
			2415130000	Electronic and Other Elec. (SIC 36): Open Top Degreasing
			2415135000	Transportation Equipment (SIC 37): Open Top Degreasing
			2415140000	Instruments and Related Products (SIC 38): Open Top Degreasing
			2415145000	Miscellaneous Manufacturing (SIC 39): Open Top Degreasing
Statewide	VOC	17	2460400000	Solvent Utilization: Miscellaneous Non-industrial: Consumer and Commercial: All Automotive Aftermarket Products

NOTE: *These control efficiencies are all applied with a rule penetration of 100 percent and a rule effectiveness of 100 percent.

Kansas

Kansas Rule 28-19-714 contains a 1.0 millimeters mercury maximum vapor pressure requirement for solvent cleaning operations, effective September 2002. Based on an evaluation of the OTC model rule for this source category, a 1.0 millimeters mercury at 68°F maximum VOC vapor pressure requirement leads to an estimated 66 percent reduction in VOC emissions relative to the national rule for cold cleaners and vapor degreasers (Pechan, 2001). The Kansas rule also includes a higher (5.0 millimeters mercury at 68°F) maximum vapor pressure requirement for the cleaning of carburetors, but this difference may not be significant relative to the OTC rule. Conveyorized degreasers are required to achieve an overall VOC control efficiency of 65 percent or greater; however, the Kansas rule does not appear to include any additional requirements relative to the national rule (other than the maximum vapor pressure requirements). Therefore, a 66 percent post-2002 VOC control efficiency was applied in Johnson and Wyandotte Counties, based on data from the OTC model rule.

Louisiana

Title 33, Part III, Section 2125 specifies additional operational requirements for open top vapor degreasers not found in EPA's 1977 CTG. One requirement of the Louisiana Code specifies a minimum 85 percent VOC reduction efficiency for open top vapor degreasers not found in the CTG. Section 2125 was last amended in April 2004.

Texas

Open-top Vapor or Conveyorized Degreasers

The national rule for vapor degreasing is estimated to achieve VOC emission reductions of between 10 and 15 percent (Pechan, 2002). The Texas rule 115.412 requires VOC emission reductions of at least 85 percent from these sources for the following counties: Bastrop, Bexar, Caldwell, Comal, Gregg, Guadalupe, Hays, Nueces, Travis, Victoria, Williamson, and Wilson. Assuming that the baseline 2002 vapor degreasing emissions include a 10 percent reduction from the national rule and that a total control of 85 percent would be applied to comply with the Texas rule, the incremental reduction from the Texas rule, relative to the 2002 emissions, is 83 percent. This rule became effective in December 2004.

Mobile Equipment Repair and Refinishing

Texas rule 115.422 requires that coating application equipment have a transfer efficiency of at least 65 percent and requires the use of high volume low pressure spray guns. This rule applies in the following counties: Dallas, El Paso, Galveston, Hardin, Harris, Jefferson, and Tarrant. Based on an evaluation of the OTC model rule for this source category, the use of "high transfer efficiency" high volume low pressure spray guns is estimated to achieve a 35 percent VOC emission reduction relative to the national rule (Pechan, 2001). Spray gun controls are estimated to contribute an additional 3 percent VOC emission reduction. However, the Texas rule contains a less stringent requirement for the enclosure of spray guns and related parts. Therefore, a 35 percent post-2002 VOC control efficiency incremental to the national rule was applied in the counties listed above to account for this rule. This rule became effective in May 2002.

Consumer Products

The national rule limits the VOC content of windshield wiper fluid to 35 percent by weight (effective December 1998). The Texas rule 115.612 limits the VOC content to 23.5 percent by weight. This represents a 33 percent reduction in the VOC content (and as a result, emissions) from the 2002 baseline. A single SCC covers all "auto aftermarket products". The fraction of emissions from auto aftermarket products that can be attributed to auto wiper fluid was estimated to be 50 percent, based on the likelihood that the other major VOC-emitting auto aftermarket products (waxes, polishes and cleaning products) are consumed in lesser volumes than windshield wiper fluid. Thus, the reduction applied to VOC emissions from the SCC representing auto aftermarket products was 17 percent. This rule became effective in February 2004.

Portable Fuel Containers

Texas has a portable fuel container rule (Statewide). In TCEQ analyses, this has been modeled as a reduction in evaporative VOC emissions using lawn and garden equipment SCCs within EPA's NONROAD model. See the Nonroad chapter for information about how the rule effects were incorporated in the analysis.

Gas-fired Water Heaters, Small Boilers, and Process Heaters

A Texas Statewide rule, adopted as part of the April 2000 Dallas/Fort Worth SIP revision, reduces NO_x emissions from new natural gas-fired water heaters, small boilers, and process heaters sold and installed in Texas beginning in 2002. The rule applies to each new water heater, boiler, or process heater with a maximum rated capacity of up to 2.0 million British thermal units per hour. This is Rule 117.461.

To simulate the effects of this rule in 2018, the following factors presented in Exhibit 7-3 were applied Statewide in Texas.

EXHIBIT 7-3. TEXAS STATEWIDE NO_X CONTROL FACTORS FOR SMALL FUEL COMBUSTORS

SCC	NO_x Control Efficiency	Rule Penetration	Rule Effectiveness	Emission Reduction
2103006000	75%	80%	100%	60%
2104006000	75%	80%	100%	60%

WRAP

Nonpoint source control factor development focused solely on California because there is little regulation of these source types in other western States.

In order to estimate the 2010 and 2020 emission benefits of air pollution emission regulations in California, a request was made to the California ARB to provide control factors that the ARB uses in its own emission projections. ARB staff provided a control factor file that was used in the Central California Ozone Study modeling effort. The Central California Ozone Study projections were based on the 1999 inventory, so the control factors are normalized to 1999. Because 2002 control factors were provided, the 2010 and 2020 control factors were normalized to a 2002 base year by the Project Team for application in this section 812 study. This normalization divides the 2010 and 2020 control factors by the associated 2002 control factors for each pollutant and source category. The California file includes control factors by district, air basin, and county, with source categories designated by California's Emission Inventory Codes. The California file has both rule-specific and composite (with all rules applied) control factors. The composite control factors were used in this analysis.

Crosswalks were developed and applied to translate California's county codes into matching FIPS codes, and to link California's Emission Inventory Codes with EPA's SCCs. This allowed the California ARB control factors to be applied to the EPA NEI nonpoint database.

EMISSION SUMMARY BY SCENARIO

Exhibit 7-4 summarizes national nonpoint source category emissions for the 2000, 2010, and 2020 *with-CAAA* scenario. National VOC emissions are dominated by evaporative emissions from solvent utilization. While there is some additional regulation of these emissions after 2002 in areas with continuing ozone nonattainment, in most areas of the country, solvent utilization emissions grow after 2002 in proportion to activity indicators like population and employment. Another prominent VOC emitting source category is Fuel Combustion-Other, which is mostly residential fireplace and woodstove emissions. (Most highly efficient fuel combustors are low VOC emitters.) Fireplace and woodstove emissions are projected to decline after 2002 as NSPS-certified woodstoves replace non-certified stoves. Another prominent VOC-emitting source category with expected emissions declines in 2010 and 2020 is fuel storage and transport. Control programs that contribute to these emission reductions include onboard VRS on gasoline-powered vehicles and more stringent State and local programs to reduce emissions at various points in the gasoline distribution system. The onboard VRS-associated emission changes are mentioned here because they apply to service station refueling emissions, which are accounted for in the nonpoint source inventory.

Exhibit 7-4 shows that national NO_x emissions for the nonpoint source sector are dominated by off-highway sources. This reflects the emissions from the three off-highway source categories that are not included in EPA's NONROAD, and are categorized as nonpoint sources in this study. These off-highway source categories are commercial marine vessels, railroad locomotives, and aircraft. NO_x emission reductions between 2002 and 2010 are a result of Federal emission standards for some commercial marine vessel engines and locomotive engines. Besides off-highway engines, the other nonpoint source NO_x emitters with more than 10 percent of total emissions for this sector are: industrial and other fuel combustion and petroleum and related industrial processes. These are all small fuel combustors that are exempt from regulations like the NO_x SIP Call because of their size. Their NO_x emissions are expected to increase slightly during the study time horizon.

SO_2 emissions for this sector are expected to stay relatively stable from 2002 to 2020. The dominant source type is industrial fuel combustion and these emissions represent coal and fuel oil combustion that occurs in sources that are not included in the 2002 NEI point source file. The off-highway sector SO_2 contribution is small because most of the off-highway source emissions are from diesel engines (commercial marine vessels and locomotives) or jet aircraft engines.

Exhibit 7-5 displays the nonpoint sector *with*- and *without-CAAA* emission summaries by pollutant in a graphic format. For all pollutants, the *without-CAAA* emissions are higher than the *with-CAAA* emissions in 2000, 2010, and 2020.

EXHIBIT 7-4. NATIONAL NONPOINTEMISSIONS BY MAJOR SOURCE CATEGORY (TPY)

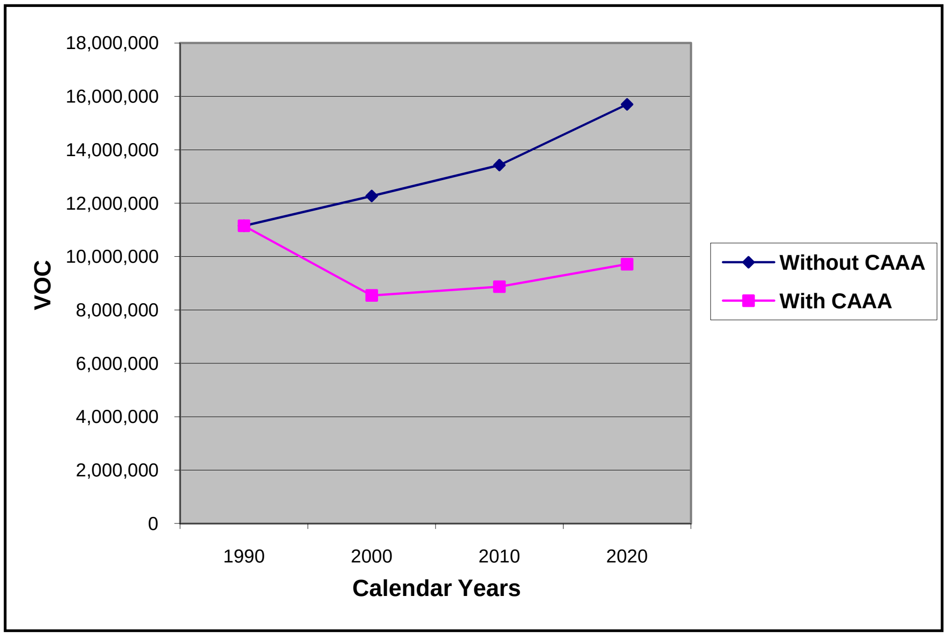
Source Category	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
VOC							
Fuel Comb. Industrial	13,050	13,770	17,624	14,656	17,952	16,262	19,190
Fuel Comb. Other	3,155,888	2,400,760	1,691,902	1,823,416	1,524,048	1,794,374	1,298,647
Chemical & Allied Product	173,405	187,443	114,430	209,748	153,860	218,894	213,670
Metals Processing	179	236	464	248	512	280	561
Petroleum & Related Industrial	357,615	376,493	470,158	398,396	491,037	400,176	443,187
Other Industrial Processes	48,586	58,000	51,500	66,974	58,595	78,528	68,885
Solvent Utilization	4,863,848	6,348,703	3,944,392	7,644,429	4,316,349	9,464,581	5,163,533
Storage & Transport	1,158,090	1,376,173	994,188	1,636,205	987,959	1,902,905	1,064,821
Waste Disposal & Recycling	595,224	699,701	367,396	804,233	393,384	961,418	465,873
Off-highway	137,427	130,430	125,547	137,454	130,583	149,706	139,238
Miscellaneous	649,492	676,901	766,743	689,717	797,969	715,555	837,944
Total	**11,152,804**	**12,268,609**	**8,544,345**	**13,425,477**	**8,872,248**	**15,702,681**	**9,715,546**
NO_x							
Fuel Comb. Industrial	824,188	844,548	498,596	857,467	518,131	996,151	547,960
Fuel Comb. Other	1,076,186	1,103,402	622,214	1,168,936	654,693	1,215,419	686,385
Chemical & Allied Product	24	28	63	31	81	37	106
Metals Processing	180	237	85	249	95	281	103
Petroleum & Related Industrial	20,346	18,960	285,674	14,361	302,603	10,588	269,148
Other Industrial Processes	2,610	3,511	11,754	4,016	14,270	4,888	17,488
Solvent Utilization	73	87	111	99	146	113	197
Storage & Transport	187	207	7,297	236	8,451	260	9,491
Waste Disposal & Recycling	79,374	93,700	66,907	106,516	74,400	119,990	83,894
Off-highway	2,532,768	2,350,865	2,147,103	2,456,076	1,866,601	2,614,494	1,856,876
Miscellaneous	232,903	234,811	245,903	232,749	248,816	236,058	253,363
Total	**4,768,841**	**4,650,355**	**3,885,707**	**4,840,735**	**3,688,289**	**5,198,279**	**3,725,010**
CO							
Fuel Comb. Industrial	153,958	156,243	269,459	158,255	286,877	176,556	304,279
Fuel Comb. Other	6,333,247	4,730,126	3,701,704	3,500,917	3,316,622	3,352,394	3,707,426
Chemical & Allied Product	0	0	84	0	100	0	120
Metals Processing	232	306	292	322	347	363	387
Petroleum & Related Industrial	4,194	3,922	244,389	3,038	265,815	2,327	236,763
Other Industrial Processes	1,048	1,447	33,682	1,701	38,873	2,160	46,133
Solvent Utilization	70	103	74	144	98	193	133
Storage & Transport	0	0	305	0	349	0	375
Waste Disposal & Recycling	1,928,632	2,253,799	1,505,769	2,531,113	1,655,137	2,809,700	1,839,997
Off-highway	792,054	787,254	754,253	820,093	812,626	901,170	900,455
Miscellaneous	7,585,669	7,700,996	8,103,956	7,692,078	8,228,264	7,843,749	8,415,419
Total	**16,799,105**	**15,634,196**	**14,613,968**	**14,707,662**	**14,605,108**	**15,088,612**	**15,451,487**

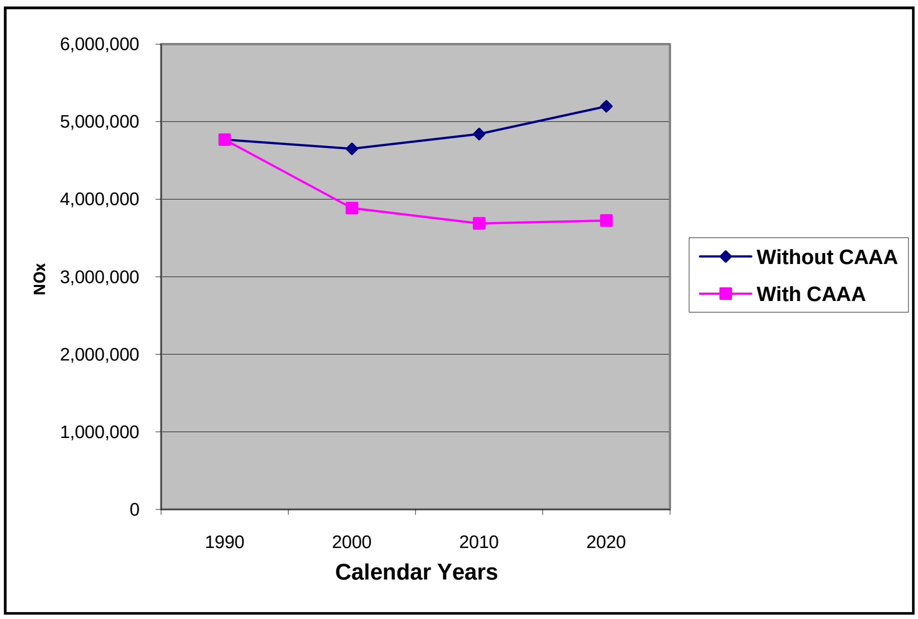
Source Category	1990	2000 *Without-CAAA*	2000 *With-CAAA*	2010 *Without-CAAA*	2010 *With-CAAA*	2020 *Without-CAAA*	2020 *With-CAAA*
SO_2							
Fuel Comb. Industrial	1,247,348	976,912	934,833	1,319,079	975,997	1,843,314	984,238
Fuel Comb. Other	583,764	561,380	509,331	635,938	546,963	669,122	565,960
Chemical & Allied Product	0	0	9	0	13	0	19
Metals Processing	0	0	45	0	49	0	53
Petroleum & Related Industrial	1,431	1,335	417	989	433	713	499
Other Industrial Processes	1,743	2,294	2,934	2,664	3,675	3,349	4,631
Solvent Utilization	0	0	23	0	31	0	43
Storage & Transport	0	0	172	0	196	0	211
Waste Disposal & Recycling	20,802	26,879	10,834	33,300	12,970	40,821	15,799
Off-highway	376,179	379,025	290,920	339,491	211,288	363,685	243,341
Miscellaneous	123,511	123,482	125,765	122,526	126,013	123,245	126,956
Total	**2,354,778**	**2,071,308**	**1,875,282**	**2,453,986**	**1,877,630**	**3,044,248**	**1,941,752**
PM_{10}							
Fuel Comb. Industrial	43,864	36,019	747,314	48,721	754,486	68,328	741,892
Fuel Comb. Other	477,269	385,481	501,763	317,971	513,618	311,381	505,386
Chemical & Allied Product	0	0	37	0	45	0	53
Metals Processing	46	52	142	49	156	53	169
Petroleum & Related Industrial	1,563	1,458	510	1,080	504	778	556
Other Industrial Processes	346,806	406,935	717,399	458,331	836,306	516,399	936,797
Solvent Utilization	0	0	1,706	0	2,317	0	3,144
Storage & Transport	0	0	465	0	541	0	613
Waste Disposal & Recycling	256,112	293,213	271,352	324,616	297,430	357,677	329,534
Off-highway	91,845	94,549	98,654	94,885	76,702	102,786	86,225
Miscellaneous	21,277,543	21,901,153	16,990,504	21,570,726	16,362,837	22,898,415	16,410,890
Total	**22,495,048**	**23,118,860**	**19,329,848**	**22,816,379**	**18,844,942**	**24,255,816**	**19,015,260**
$PM_{2.5}$							
Fuel Comb. Industrial	not estimated[51]	186,130	186,522	193,876	190,237	200,360	189,348
Fuel Comb. Other	not estimated	558,855	457,757	635,723	469,581	682,438	463,063
Chemical & Allied Product	not estimated	0	24	0	28	0	34
Metals Processing	not estimated	39	85	37	93	40	101
Petroleum & Related Industrial	not estimated	1,458	497	1,080	491	778	541
Other Industrial Processes	not estimated	218,895	214,736	253,527	249,036	291,632	284,196
Solvent Utilization	not estimated	0	1,694	0	2,300	0	3,121
Storage & Transport	not estimated	0	460	0	534	0	606
Waste Disposal & Recycling	not estimated	366,785	255,033	401,714	278,813	439,440	307,960
Off-highway	not estimated	74,198	85,996	76,216	66,357	82,433	74,580
Miscellaneous	not estimated	2,960,812	2,900,444	2,796,180	2,802,553	2,920,659	2,842,995
Total	**4,198,487**	**4,367,172**	**4,103,247**	**4,358,354**	**4,060,026**	**4,617,781**	**4,166,546**

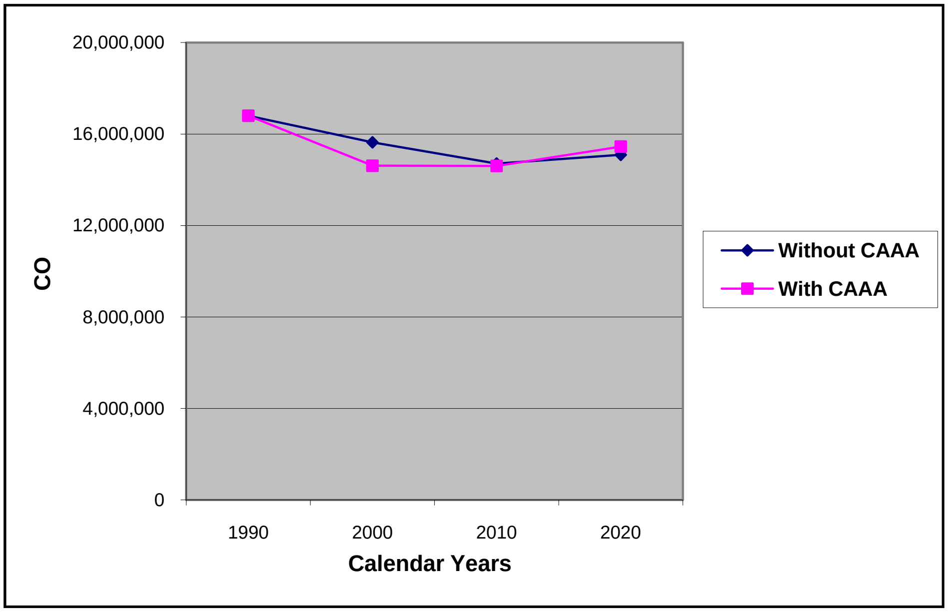
[51] The Project Team determined that the 1990 NEI did not accurately measure $PM_{2.5}$ emissions. The Project Team estimated revised national emissions for 1990 but did not develop revised emissions estimates by major source category.

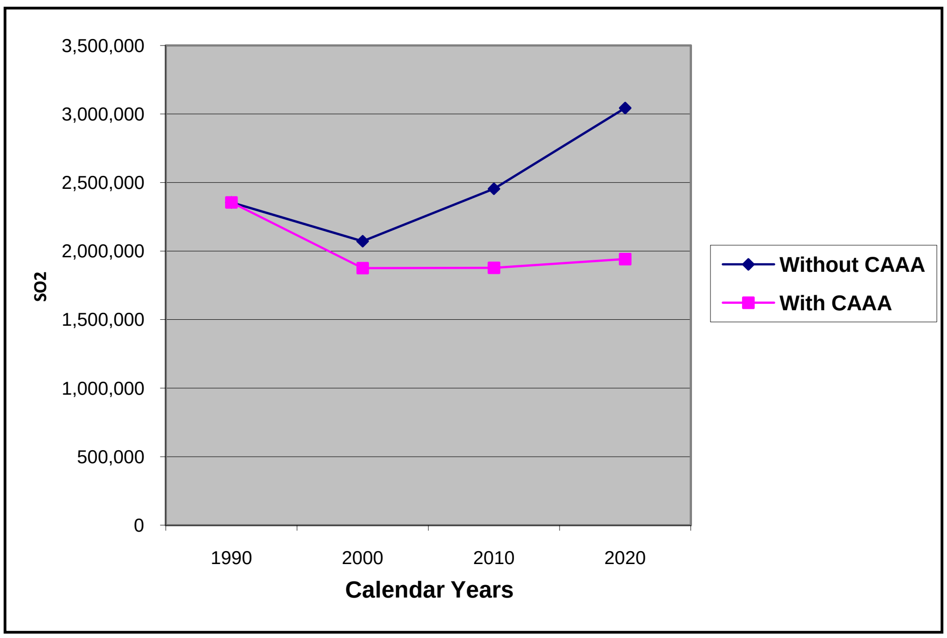
Source Category	**1990**	**2000 *Without-CAAA***	**2000 *With-CAAA***	**2010 *Without-CAAA***	**2010 *With-CAAA***	**2020 *Without-CAAA***	**2020 *With-CAAA***
NH_3							
Fuel Comb. Industrial	9,328	10,153	11,968	10,729	12,676	12,810	13,568
Fuel Comb. Other	27,143	22,214	19,105	18,961	20,176	18,738	20,464
Chemical & Allied Product	0	0	61	0	79	0	100
Metals Processing	0	0	5	0	6	0	7
Petroleum & Related Industrial	0	0	0	0	0	0	0
Other Industrial Processes	47,582	64,995	59,797	78,108	75,235	99,899	95,854
Solvent Utilization	0	0	59	0	69	0	80
Storage & Transport	0	0	22	0	22	0	23
Waste Disposal & Recycling	92,633	109,121	22,675	128,110	25,629	162,830	31,497
Off-highway	663	553	246	489	280	520	331
Miscellaneous	3,079,791	3,414,812	3,437,628	3,592,072	3,578,989	3,835,818	3,824,860
Total	**3,257,139**	**3,621,848**	**3,551,567**	**3,828,468**	**3,713,161**	**4,130,614**	**3,986,783**

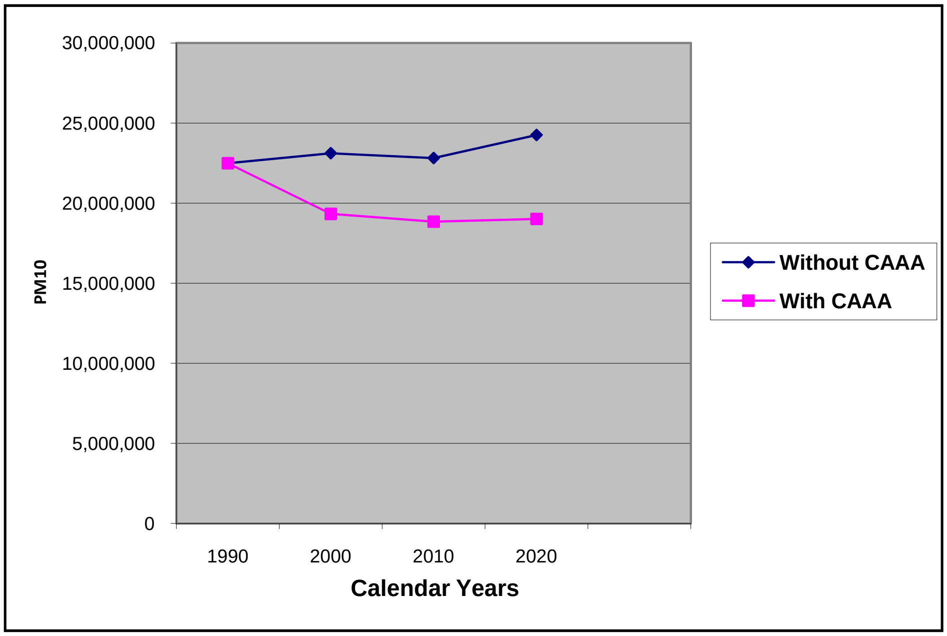
EXHIBIT 7-5. *WITH-* AND *WITHOUT-CAAA* SCENARIO NONPOINT EMISSION SUMMARIES BY POLLUTANT

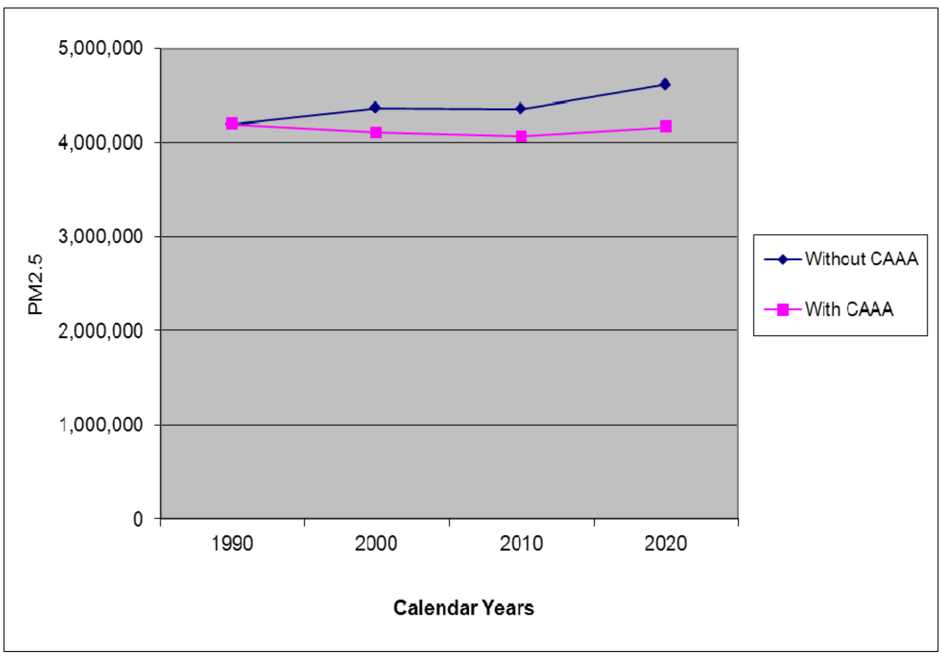





20,000,000
16,000,000
12,000,000
8,000,000
4,000,000
0
CO
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


3,500,000
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
SO2
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
PM10
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


5,000,000
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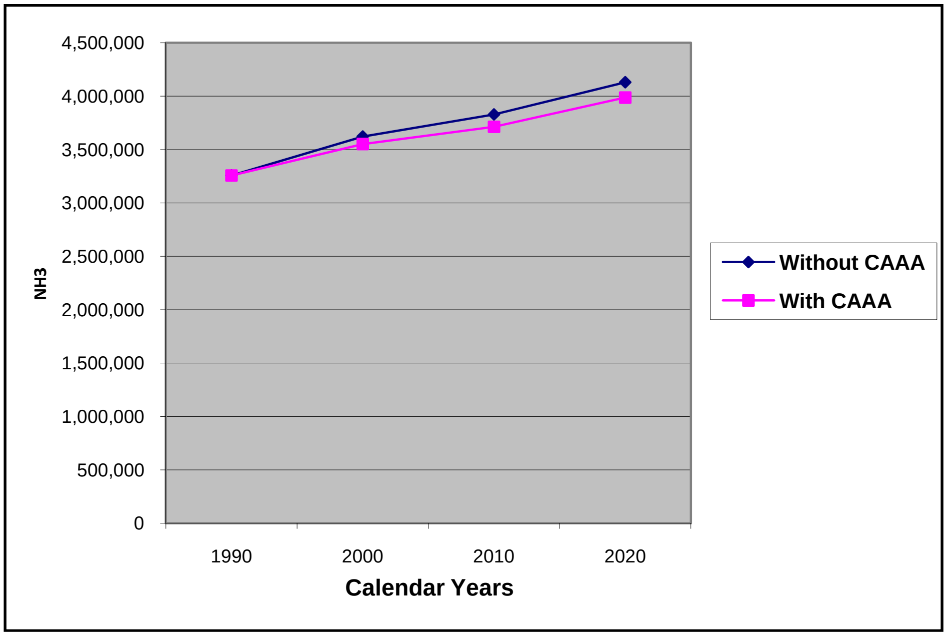
PM2.5
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA


4,500,000
4,000,000
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2,000,000
1,500,000
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0
NH3
1990
2000
2010
2020
Calendar Years
Without CAAA
With CAAA

CHAPTER 8 | LOCAL CONTROL MEASURE ANALYSIS

OVERVIEW OF APPROACH

The emission projections described in the previous chapters of this report reflect Federal measures and state and local control programs that were on-the-books as of September 2005, but do not include the additional local measures expected to be adopted to achieve further progress toward 8-hour ozone and $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS) attainment. This chapter describes the analysis that was performed to estimate the emission reductions resulting from implementation of the 8-hour ozone NAAQS, the $PM_{2.5}$ NAAQS, and the Clean Air Visibility Rule, or CAVR (sometimes referred to as the best available retrofit technology, or BART, rule). These rules are taken in their proposed or promulgated form as of January 2008.[52] The baseline for performing this local control measures evaluation is the core scenario from the *with-CAAA* 2010 and 2020 cases. Source-specific emissions are used for all EGU and non-EGU point source analyses. The 2010 and 2020 core scenario emission estimates for onroad, nonroad and nonpoint sectors are at the county-level.

The local control measure analysis was performed in three steps: 8-hour ozone NAAQS implementation; CAVR rule implementation; and PM NAAQS implementation. Note that our analysis assumes that efforts toward compliance with the 1-hour ozone NAAQS and the current PM_{10} NAAQS for historical years are captured in the core scenarios as they currently exist, which include local controls identified by RPOs and which are described in the previous chapters of this report.

The main cost and control measure database used for these analyses was developed from version 4.1 of AirControlNET released in September 2005, with some updates to incorporate 1-hour ozone NAAQS local control measure information and additional onroad mobile source control measures. The analysis year for the ozone and PM NAAQS analyses is 2010; the Project Team applied local controls identified for 2010 to generate results for 2020. The analysis year for the CAVR is 2020, since it is expected that the majority of controls implemented to satisfy these rule requirements will occur after 2010. The methods used for each analysis are described below, in the order in which they were implemented as further incremental reductions from the core scenario emissions inventories.

[52] CAMR has been vacated, CAIR has been vacated & then remanded – revisions are still pending as of March 2009.

8-HOUR OZONE ANALYSIS

This analysis focuses on the implementation of emission controls in nonattainment areas (NAAs) in the United States. The corresponding analysis of the costs of these controls is presented in a separate report. These nonattainment areas are divided into two overlapping groups. The first group includes areas where additional local controls are anticipated to be needed to meet the NAAQS by 2010. Reduction target levels for this group of areas were derived directly from the area-specific target emissions reduction levels derived to support the ozone implementation economic analysis (Pechan 2005a). Because percentage reduction (both VOC and NO_x) emission targets were used, and because the Federal rule inventories and target years used in the 812 analysis differ from those used in the ozone economic analysis (the 812 analysis starts from a 2002 baseline, while the previous EPA analyses use a 2001 platform–developed from a 1999 NEI baseline), the actual absolute reductions for each nonattainment area differ slightly from those modeled in the implementation economic analysis.

The second group consists of 8-hour ozone nonattainment areas for which certain mandatory Clean Air Act (CAA) control obligations for moderate and above areas are required pursuant to Subpart 2 of the Act. Mandatory controls include adoption of an inspection and maintenance program for light-duty vehicles and a 15 percent VOC emission reduction requirement. For purposes of this analysis, we assume that both Group 1 and Group 2 areas require adoption of reasonable available control technology (RACT) on large stationary sources (those emitting more than 100 tons of VOC or NO_x per year) in areas that have not already adopted RACT. It should be noted that, under the CAA, states determine RACT levels and applicability on a case-by-case or source category basis considering EPA guidance and other information. Therefore, RACT levels eventually set by individual states may differ from the RACT levels adopted for this analysis.

An important caveat for the 8-hour ozone NAAQS attainment analysis is that VOC and NO_x emission reduction targets were not estimated by EPA for California 8-hour ozone nonattainment areas. This decision was motivated primarily by poor model performance at the time simulations were conducted for ozone concentrations in various ozone nonattainment areas within California. Therefore, for selected 8-hour ozone nonattainment areas in California, an alternate process was used to estimate the emission reduction targets for controls beyond RACT and I/M, described in the following section.

1. RACT AND I/M

To estimate the contributions of electricity generating units (EGUs) and non-EGU point sources toward achieving the emission reductions needed to attain, this analysis applied RACT controls on EGUs and non-EGU point sources where RACT was required. It should be noted, however, that the Phase II implementation rule determined that the Clean Air Interstate Rule (CAIR) satisfies RACT for participating

EGUs in states where all required CAIR reductions are obtained from EGUs. As a general rule, 8-hour ozone nonattainment area counties were assumed to have already met their RACT requirements if they were previously designated as nonattainment of the 1-hour ozone NAAQS.

For this study, RACT applicability was determined on a control measure basis by adapting criteria initially developed for the 8 hour ozone NAAQS implementation economic analysis. Note that all of the criteria have to be met:

- Current NO_x control efficiency is zero, i.e., it is an uncontrolled source in 2002;
- Total annual NO_x emissions of the source greater than 100 tons (i.e., large source);
- Control efficiency of the control is less than 81 percent for NO_x;
- Control cost is less than $1,580 per ton NO_x reduced (i.e., cost effective control is available); and
- Control measure has the lowest NO_x control efficiency from all that are available for that source (i.e., minimum control available).

I/M controls are then applied to counties where required. Once I/M and RACT controls were applied, the cost of meeting the additional emission reduction requirements (RFP and Target levels) were determined for each area by using control techniques, efficiencies, and cost databases in concert with the incremental emission reduction and progress requirements mentioned above. For additional local controls, a least-cost algorithm was used to identify and apply the control measures to meet the progress requirements, where applicable. First, the potential sources of emission and reductions and their costs were identified. Next, the lowest cost, second lowest, third lowest, and so forth, control measures were selected until the progress requirement was met. Because of the discrete nature of control measures and their efficiencies, sometimes the emission reduction or progress target is exceeded. Any excess might be used as an offset against new source growth emissions, if the excess were significant.

2. RFP

Reasonable further progress (RFP) is the attainment program element requiring incremental reductions in the emissions of the applicable air pollutant pursuant to Part D of the Clean Air Act (CAA) and its Amendments. The RFP requirements in the CAAA are intended to ensure that each ozone nonattainment area makes progress toward achieving sufficient precursor emission reductions to attain the national ambient air quality standards for ozone. More specifically, the Act requires certain ozone nonattainment areas classified as moderate or above to achieve actual VOC emission reductions of at least 15 percent over an initial 6-year period, and subsequently to achieve further emission reduction progress of three percent per year averaged over each consecutive three-year period until attainment.

The first step needed to determine if additional RFP emission reductions are required in certain 8-hour ozone nonattainment areas is to compare VOC emission estimates of 2002 with 2008. This is because the VOC emission reduction requirements obtained from 2002 to 2008 as a result of on-the-books Federal and local air pollution control programs count toward the 15 percent reduction requirement. For the 8-hour Ozone Implementation rule, 2002 is the base year. Exhibit 8-1 shows the VOC progress requirements to meet a 15 percent reduction from 2002 emission levels by 2008. The 15 percent reduction calculation allows 100 percent credit for VOC reductions achieved from 2002 to 2008 through implementation of other emission reduction programs, such as implementation of Ozone Transport Commission model rules to reduce VOC solvent emissions. The 2008 emissions were estimated by interpolating 2002 and 2010 emission estimates.

EXHIBIT 8-1. REASONABLE FURTHER PROGRESS REQUIREMENTS FOR VOC IN DESIGNATED 8-HOUR OZONE NONATTAINMENT AREAS

Area Name	Base Case 2008 VOC Emissions (tons)	Estimated Additional VOC Reductions to Meet 15% RFP Requirements (tons)	Estimated Additional VOC Reductions Observed in 2008 as a % of 2008 Base Case Emissions
Allegan Co, MI	11,446	1,876	16.4%
Atlanta, GA	228,148	3,637	1.6%
Baltimore, MD	95,268	13,256	13.9%
Beaumont-Port Arthur, TX	40,683	8,607	21.2%
Buffalo-Niagara Falls, NY	65,367	2,325	3.6%
Chicago-Gary-Lake County, IL-IN	92,000	-	0.0%
Cleveland-Akron-Lorain, OH	126,044	13,319	10.6%
Columbus, OH	58,772	5,245	8.9%
Dallas-Fort Worth, TX	162,128	33,197	20.5%
Detroit-Ann Arbor, MI	170,290	11,253	6.6%
Door Co, WI	4,412	1,184	26.8%
Houston-Galveston-Brazoria, TX	210,185	49,043	23.3%
Indianapolis, IN	58,050	-	0.0%
Kent and Queen Anne's Cos, MD	3,918	90	2.3%
Kern Co (Eastern Kern), CA	33,816	1,115	3.3%
Knoxville, TN	48,788	2,372	4.9%
Los Angeles South Coast Air Basin, CA	297,667	6,790	2.3%
Milwaukee-Racine, WI	99,269	12,621	12.7%
Nevada Co. (Western Part), CA	4,461	-	0.0%
New York-N. New Jersey-Long Island, NY-NJ	571,745	-	0.0%
Philadelphia-Wilmin-Atlantic Ci, PA-NJ-MD	256,489	9,401	3.7%
Providence (All RI), RI	26,859	-	0.0%
Raleigh-Durham-Chapel Hill, NC	64,458	9,134	14.2%
Sacramento Metro, CA	61,301	5,173	8.4%
San Diego, CA	73,409	9,265	12.6%
San Joaquin Valley, CA	106,002	11,941	11.3%
Sheboygan, WI	8,771	1,538	17.5%
South Bend-Elkhart, IN	24,937	266	1.1%
Ventura Co, CA	24,718	6,802	27.5%
Washington, DC-MD-VA	135,314	10,785	8.0%
Youngstown-Warren-Sharon, OH-PA	29,605	1,104	3.7%

The one exception to the 100 percent credit allowance is that mobile source reductions are discounted by 13 percent (i.e., only 87 percent of mobile source reductions are creditable toward the RFP progress requirements). The reason this discount is applied is because there are certain reductions in motor vehicle emissions that will occur in the future, but are the result of actions taken prior to the enactment of the 1990 CAAA. (The methods to account for non-creditable reductions when calculating RFP Targets for the 2008 and Later RFP Milestone Years is provided in Appendix A to the Preamble for the Final Rule to Implement the 8-Hour Ozone NAAQS, at 70 FR 71612.)

The reductions required to meet RFP targets are allowed from sources within 100 km radius for VOC reductions and within 200 km radius for NO_x reductions. However, each time a source/control measure from outside the nonattainment area boundary was selected to meet an RFP target requirement, the RFP target for that area was recalculated. RFP target recalculation was performed by adding the selected source emissions to the base inventory of the area. The RFP target recalculation followed the RFP target calculation methods described below.

3. RFP CALCULATION METHODOLOGY

The first step in determining if additional RFP emission reductions are required is to compare VOC emission estimates for calendar year 2002 with those estimated for 2008. This computation is necessary because the VOC emission reductions obtained from 2002 to 2008 as a result of on-the-books Federal and local air pollution control programs count toward the 15 percent reduction requirement.

The RFP requirement for each nonattainment area is calculated by subtracting 85 percent of 2002 emissions (i.e., reduction by 15 percent) from the 2008 emissions, assuming that mobile source emission changes are discounted by 13 percent. If this value is greater than zero, this is the RFP reduction requirement for that nonattainment area. If that value is less than or equal to zero, no further RFP reduction is required.

Below is a sample calculation for Baltimore, MD nonattainment area:

2002 emissions totals = 99,796 tons VOC

2010 with CAAA scenario emissions totals = 93,758 tons

Interpolation of 2002& 2010 yields 2008 emissions = 95,267 tons

After discounting of mobile emissions by 13 percent, 2002 emission = 96,484 tons.

Additional VOC tons required to reduce = (2008 Emissions) - (85 percent of discounted 2002 Emissions)

= (95,267) - (0.85 x 96,484)

= 13,256 tons

4. ADDITIONAL EMISSION REDUCTIONS TO MEET TARGETS

Similarly, and after applying I/M, RACT, and RFP, if an area required additional reductions to meet their emission reduction target for NO_x and/or VOC (e.g., Group 1 areas), source/controls within 100 km radius for VOC reductions and within 200 km radius for NO_x reductions are selected on a least cost basis, as described above for RFP. No controls are selected that exceed a $15,000/ton cost-effectiveness threshold. Exhibits 8-2a and 8-2b provide the NO_x and VOC emission reduction results by NAA for 2010 and 2020, respectively. Emission reductions shown for these nonattainment areas include RACT reductions, RFP-associated reductions, as well as bringing areas into attainment with the 8-hour ozone requirements.

EXHIBIT 8-2A. 8-HOUR OZONE EMISSION REDUCTION RESULTS FOR 2010

	VOC Emission Reduction (tons)					NOx Emission Reduction (tons)				
Area Name	**EGU**	**Point**	**Nonpoint**	**Onroad**	**Nonroad**	**EGU**	**Point**	**Nonpoint**	**Onroad**	**Nonroad**
Albany-Schenectady-Troy, NY	-	-	-	53	-	-	6,292	74	454	-
Allegan Co, MI	-	-	1,299	123	-	-	-	-	146	-
Amador and Calaveras Cos (Central Mtn), CA	-	-	600	-	-	-	-	26	-	-
Atlanta, GA	-	-	2,052	-	-	-	-	112	-	-
Baltimore, MD	-	58	15,111	-	-	4,615	2,280	515	841	-
Beaumont-Port Arthur, TX	-	-	1,876	462	-	-	13,417	53	665	-
Buffalo-Niagara Falls, NY	-	-	1,725	-	-	3,462	612	154	-	-
Chicago-Gary-Lake County, IL-IN	-	79	11,016	-	-	2,174	3,395	584	-	-
Chicago-Gary-Lake County, IL-IN (Cook, IL & Lake, IN)	-	270	27,636	-	-	3,644	11,168	1,227	-	-
Chico, CA	-	-	1,298	8	-	-	111	21	92	-
Cleveland-Akron-Lorain, OH	-	-	7,153	-	-	3,803	444	205	-	-
Columbus, OH	-	-	3,821	1,447	-	-	1,158	54	1,565	-
Dallas-Fort Worth, TX	-	62	20,952	1,650	-	-	6,856	86	1,750	-
Detroit-Ann Arbor, MI	-	68	9,880	4,506	-	-	-	-	4,951	-
Door Co, WI	-	-	44	27	-	-	-	-	31	-
Greater Connecticut, CT	-	-	12,915	92	-	418	1,235	145	804	-
Houston-Galveston-Brazoria, TX	-	85	16,174	1,818	-	545	19,514	589	4,163	-
Imperial, CA	-	-	692	-	-	-	-	-	-	-
Indianapolis, IN	-	-	-	-	-	345	98	54	-	-
Jamestown, NY	-	-	615	-	-	6,572	133	21	-	-
Kent and Queen Anne's Cos, MD	-	-	575	21	-	-	-	5	77	-
Knoxville, TN	-	-	1,492	899	-	416	1,029	-	953	-
Los Angeles South Coast Air Basin, CA	-	-	13,431	-	-	2,435	11,930	677	-	-
Manitowoc, WI	-	-	268	8	-	203	27	14	79	-
Mariposa and Tuolumne Cos (Southern Mtn), CA	-	-	600	21	-	-	116	-	50	-
Milwaukee-Racine, WI	-	32	5,449	87	-	5,743	1,256	286	695	-
Nevada (Western Part), CA	-	-	501	-	-	-	-	3	-	-

EXHIBIT 8-2A. 8-HOUR OZONE EMISSION REDUCTION RESULTS FOR 2010

	VOC Emission Reduction (tons)					NOx Emission Reduction (tons)				
Area Name	**EGU**	**Point**	**Nonpoint**	**Onroad**	**Nonroad**	**EGU**	**Point**	**Nonpoint**	**Onroad**	**Nonroad**
New York-N. New Jersey-Long Island, NY-NJ-CT)	-	188	93,994	53	-	3,585	5,700	2,098	3,741	-
Philadelphia-Wilmin-Atlantic City; PA-NJ-MD-DE	-	10	48,255	75	-	13,155	7,597	1,149	1,891	-
Poughkeepsie, NY	-	-	5,323	29	-	3,644	16	65	408	-
Providence (All RI), RI	-	-	-	47	-	-	267	101	387	-
Raleigh-Durham-Chapel Hill, NC	-	91	9,013	32	-	919	-	-	34	-
Rochester, NY	-	-	52	-	-	1,168	2,359	171	-	-
Sacramento Metro, CA	-	70	5,538	39	-	-	2,735	205	495	-
San Diego, CA	-	-	8,616	-	-	-	-	-	-	-
San Francisco Bay Area, CA	-	-	8,225	50	-	1,288	8,758	366	638	-
San Joaquin Valley, CA	-	38	13,626	-	-	2,244	9,632	1,281	-	-
Sheboygan, WI	-	10	937	9	-	288	94	22	80	-
South Bend-Elkhart, IN	-	-	333	-	-	-	-	106	-	-
Ventura Co, CA	-	-	3,686	-	-	-	499	53	-	-
Washington, DC-MD-VA	-	-	7,990	10	-	2,379	1,138	361	693	-
Youngstown-Warren-Sharon, PA-OH	-	-	147	-	-	-	-	-	-	-
Subtotal	-	***1,061***	***362,913***	***11,566***	-	***63,044***	***119,868***	***10,883***	***25,683***	-
All Others	-	*410*	*74,682*	*1,309*	-	*73,860*	*95,251*	*2,466*	*7,190*	-
Total	-	**1,471**	**437,596**	**12,875**	-	**136,904**	**215,119**	**13,349**	**32,873**	-

EXHIBIT 8-2B. 8-HOUR OZONE EMISSION REDUCTION RESULTS FOR 2020

	VOC Emission Reduction (tons)					NOx Emission Reduction (tons)				
Area Name	**EGU**	**Point**	**Nonpoint**	**Onroad**	**Nonroad**	**EGU**	**Point**	**Nonpoint**	**Onroad**	**Nonroad**
Albany-Schenectady-Troy, NY	-	-	-	17	-	-	5,956	78	50	-
Allegan Co, MI	-	-	1,482	202	-	-	-	-	207	-
Amador and Calaveras Cos (Central Mtn), CA	-	-	-	-	-	-	-	1	-	-
Atlanta, GA	-	-	2,499	-	-	217	522	133	-	-
Baltimore, MD	-	104	15,769	-	-	3,275	2,609	558	34	-
Beaumont-Port Arthur, TX	-	-	2,364	671	-	-	15,035	55	611	-
Buffalo-Niagara Falls, NY	-	-	1,559	19	-	2,053	1,144	152	52	-
Chicago-Gary-Lake County, IL-IN	-	87	12,568	-	-	2,174	4,715	604	-	-
Chicago-Gary-Lake County, IL-IN (Cook, IL & Lake, IN)	-	297	31,131	-	-	3,696	7,416	1,269	-	-
Chico, CA	-	-	-	-	-	-	-	4	-	-
Cleveland-Akron-Lorain, OH	-	-	7,022	-	-	3,746	375	115	-	-
Columbus, OH	-	-	2,840	2,267	-	-	1,205	53	2,140	-
Dallas-Fort Worth, TX	-	98	25,750	2,945	-	-	7,753	96	2,784	-
Detroit-Ann Arbor, MI	-	83	8,270	6,658	-	-	-	-	6,377	-
Door Co, WI	-	-	59	42	-	-	-	-	42	-
Greater Connecticut, CT	-	-	14,685	30	-	418	1,377	155	88	-
Houston-Galveston-Brazoria, TX	-	113	20,135	2,769	-	755	22,076	614	2,896	-
Imperial, CA	-	-	1,388	100	-	-	185	108	206	-
Indianapolis, IN	-	-	-	-	-	345	127	55	-	-
Jamestown, NY	-	-	715	4	-	3,272	137	20	13	-
Kent and Queen Anne's Cos, MD	-	-	598	25	-	-	-	5	31	-
Knoxville, TN	-	-	935	1,425	-	416	1,069	-	1,327	-
Los Angeles South Coast Air Basin, CA	-	183	34,684	-	-	-	15,063	781	-	-
Manitowoc, WI	-	-	330	2	-	203	30	14	8	-
Mariposa and Tuolumne Cos (Southern Mtn), CA	-	-	792	-	-	-	-	-	-	-
Milwaukee-Racine, WI	-	30	5,626	28	-	4,127	1,409	301	76	-
Nevada (Western Part), CA	-	-	380	-	-	-	-	-	-	-
New York-N. New Jersey-Long Island, NY-NJ-CT)	-	208	107,616	19	-	2,017	6,333	2,163	185	-

EXHIBIT 8-2B. 8-HOUR OZONE EMISSION REDUCTION RESULTS FOR 2020

	VOC Emission Reduction (tons)					NOx Emission Reduction (tons)				
Area Name	**EGU**	**Point**	**Nonpoint**	**Onroad**	**Nonroad**	**EGU**	**Point**	**Nonpoint**	**Onroad**	**Nonroad**
Philadelphia-Wilmin-Atlantic City; PA-NJ-MD-DE	-	12	52,887	25	-	13,836	6,065	1,191	123	-
Poughkeepsie, NY	-	-	6,218	10	-	654	17	65	34	-
Providence (All RI), RI	-	-	-	15	-	-	259	106	43	-
Raleigh-Durham-Chapel Hill, NC	-	80	9,191	51	-	919	-	-	47	-
Rochester, NY	-	-	46	25	-	1,496	2,316	168	71	-
Sacramento Metro, CA	-	-	5,723	-	-	-	52	40	-	-
San Diego, CA	-	-	9,714	24	-	-	942	123	203	-
San Francisco Bay Area, CA	-	-	1,928	-	-	-	874	35	-	-
San Joaquin Valley, CA	-	75	14,446	-	-	-	8,257	879	-	-
Sheboygan, WI	-	21	934	3	-	288	103	24	9	-
South Bend-Elkhart, IN	-	-	232	-	-	-	-	105	-	-
Ventura Co, CA	-	-	4,531	4	-	-	571	55	45	-
Washington, DC-MD-VA	-	-	7,268	4	-	3,086	1,260	443	36	-
Youngstown-Warren-Sharon, PA-OH	-	-	178	-	-	-	-	-	-	-
Subtotal	-	***1,391***	***412,490***	***17,385***	-	***46,991***	***115,253***	***10,567***	***17,739***	-
All Others	-	472	77,965	1,242	-	54,157	93,987	2,478	1,621	-
Total	-	**1,863**	**490,454**	**18,627**	-	**101,148**	**209,240**	**13,045**	**19,360**	-

Exhibits 8-2a and 8-2b show the projected VOC and NO_x emission reductions by sector that are estimated by this analysis to be selected as part of the attainment plan for each 8-hour ozone nonattainment area. For VOC, this Exhibit shows that for most nonattainment areas, the majority of the expected emission reductions will come from the nonpoint source sector. This is to be expected as most of the major stationary source VOC emitters have previous control requirements via RACT requirements in 1-hour ozone control plans and/or Maximum Achievable Control Technology (MACT) requirements as part of the CAAA90 Title III hazardous air pollutant (HAP) control program. Nonpoint source VOC control selection examples include controlling solvents beyond Federal requirements in states that have not already adopted the Ozone Transport Commission (OTC) model rules, and the OTC states select more stringent solvent control measures, such as those that have been adopted in certain California air pollution control districts.

Exhibits 8-2a and 8-2b show that NO_x control measure selection is more evenly spread among the sectors than the VOC selection. NO_x control measure choices in any individual area are a function of the source mix and the availability of cost effective controls by sector. EGU NO_x controls in the 8-hour ozone nonattainment area are typically selective catalytic reduction (SCR) installations at units that have not already installed these controls to meet acid rain, Clean Air Interstate Rule (CAIR), or NO_x SIP Call requirements. Non-EGU point source NO_x controls selected include low NO_x burners, selective non-catalytic reduction (SNCR), and SCR installation on various industrial fuel combustors (heaters, boilers, kilns and incinerators). Onroad NO_x emission reductions in Exhibits 8-2a and 8-2b reflect diesel retrofits and restricted idling practices.

Note that the modeled VOC and NOx emission reductions for some 8-hour ozone nonattainment areas are not sufficient to bring them into attainment of the 8-hour standard (based on the emission reduction targets that were used). Exhibits 8-3a and 8-3b provide an overview of 2010 and 2020 VOC and NO_x emission reduction targets and the reductions in 2010 and 2020 emissions that were available in AirControlNET to achieve emission reductions during these respective time periods. The 8-hour ozone nonattainment areas not listed in Exhibits 8-3a and 8-3b are either projected to attain the NAAQS by 2010 (for Exhibit 8-3a) or 2020 (for Exhibit 8-3b) based on projected emission changes since their designation, or they are California ozone nonattainment areas for which emission reduction targets were estimated separately.

The emission reductions from identified measures listed in Exhibits 8-3a and 8-3b do not match the total emission reductions for many nonattainment areas in Exhibits 8-2a and 8-2b. The reason is that in these areas emission reductions for NAAQS attainment targets include controls applied to sources within 100km or 200km of the nonattainment area for VOC and NO_x emissions, respectively. Thus some emission reductions listed in Exhibits 8-2a and 8-2b are legitimately counted under multiple nonattainment areas in 8-3a and 8-3b, such as in New York and Philadelphia, where nonattainment areas are adjacent to one another.

Depending on the modeled response of ozone concentrations to changes in VOC and NO_x emissions, VOC and NO_x emission reduction targets are within the range of zero to 50 percent reductions in these pollutants, with the VOC emission reduction target often being zero (i.e., no additional emission reduction in 2010 is expected to be needed from the emission levels achieved in the *with-CAAA* scenario). Because the VOC and NO_x emission reduction columns include the emission reductions associated with meeting RACT and RFP requirements, these emission reductions can be well above the pollutant-specific targets (especially when the target is zero).

Exhibits 8-3a and 8-3b show that applying known identifiable control measures are insufficient to achieve the needed VOC emission reductions to attain the 8-hour ozone NAAQS in four nonattainment areas outside of California: Chicago, Houston-Galveston, New York, and Philadelphia. Chicago is listed twice in Exhibits 8-3a and 8-3b because Cook County, IL and Lake County, IN have separate attainment targets from those estimated for the remaining counties in the nonattainment area. In total, the VOC emissions shortfall in these four 8-hour ozone nonattainment areas is about 246,000 tons per year in 2010. New and innovative emission control measures would be needed to achieve further reductions at reasonable cost in VOC emissions beyond what is shown in Exhibit 8-3a.

EXHIBIT 8-3A. COMPARISON OF ATTAINMENT TARGETS WITH REDUCTIONS ACHIEVED VIA LOCAL MEASURES IN 2010

Area Name	VOC Reduction Target (tons)	VOC Reduced, Identified Measures (tons)	Remainder Unidentified Measures (tons)	NO_x Reduction Target (tons)	NO_x Reduced, Identified Measures (tons)	Remainder Unidentified Measures (tons)
Atlanta	-	3,667		6,609	7,223	-
Baltimore	-	14,804	-	31,685	16,740	14,945
Beaumont	-	4,342	-	3,178	3,389	-
Buffalo	-	2,654	-	13,551	14,856	-
Chicago - Cook/Lake Cos.	42,331	28,596	13,735	40,539	41,063	-
Chicago - Rest	31,555	27,906	3,649	22,904	20,202	2,702
Cleveland	-	13,294	-	19,111	21,313	-
Dallas - FT Worth	-	26,673	-	30,613	32,547	
Detroit	17,817	17,927	-	-	4,951	-
Houston - Galveston	107,591	22,557	85,034	125,742	66,029	59,713
Kent and Queen Annes	-	95	-	142	340	-
Milwaukee	-	14,453	-	30,253	24,430	5,823
New York	264,064	128,845	135,219	180,417	41,274	139,144
Philadelphia	120,967	112,744	8,223	103,440	85,896	17,544
Providence	-	47	-	2,668	755	1,913
Sheboygan	-	1,614	-	2,899	3,623	-
Washington	-	10,791	-	16,446	18,041	-
Total		**431,008**	**245,861**		**402,670**	**241,785**

Note: In the Chicago, IL-IN 8-hour ozone nonattainment area, Cook County IL and Lake County, IN have separate attainment targets from those estimated for the remaining counties in the nonattainment area. Therefore, these two areas are shown separately in this exhibit. Totals may not add due to rounding

Exhibit 8-3a also shows that there are expected NO_x emission reduction shortfalls in seven 8-hour ozone nonattainment areas in 2010, with these shortfalls ranging from as little as 1,913 tons (in Providence) to 140,000 tons (in the New York City nonattainment area). Factors affecting an area's ability to achieve significant NO_x emission reductions from the 2010 *with-CAAA* scenario include whether the area's major EGU NO_x sources are already well controlled in the core scenario, the presence or absence of a significant industrial base in the nonattainment area (or within a 200 km radius), and their existing 2010 control programs for stationary source NO_x emitters. For example, the Houston-Galveston area NO_x control simulation begins with a NO_x emission cap applied to non-EGU point sources in the region that is equivalent to a 55 percent reduction from uncontrolled NO_x emissions for these sources. Therefore, the control opportunities in Houston-Galveston for the local measures analysis include (1) taking major non-EGU sources to a higher level of NO_x control, (2) applying RACT-level controls to smaller NO_x sources (those emitting 25 tons per year or above), and (3) applying controls to sources outside the nonattainment area, but within a 200 km radius.

EXHIBIT 8-3B. COMPARISON OF ATTAINMENT TARGETS WITH REDUCTIONS ACHIEVED VIA LOCAL MEASURES IN 2020

Area Name	VOC Reduction Target (tons)	VOC Reduced, Identified Measures (tons)	Remainder Unidentified Measures (tons)	NO_x Reduction Target (tons)	NO_x Reduced, Identified Measures (tons)	Remainder Unidentified Measures (tons)
Atlanta	-	3,637	-	6,609	9,756	-
Baltimore	-	13,659	-	31,685	14,054	17,631
Beaumont	-	5,438	-	3,178	-	-
Buffalo	-	2,646	-	13,551	11,152	-
Chicago - Cook/Lake Cos.	42,331	33,028	9,303	40,539	41,161	-
Chicago - Rest	31,555	31,428	127	22,904	21,364	1,540
Cleveland	-	13,394	-	19,111	20,655	-
Dallas - FT Worth	-	33,221	-	30,613	32,834	-
Detroit	17,817	17,817	-	-	6,377	-
Houston - Galveston	107,591	28,100	79,491	125,742	68,678	57,064
Kent and Queen Annes	-	90	-	142	145	-
Milwaukee	-	13,374	-	30,253	23,631	6,622
New York	264,064	146,204	117,860	180,417	30,885	149,532
Philadelphia	120,967	121,551	-	103,440	69,074	34,366
Providence	-	15	-	2,668	428	2,240
Sheboygan	-	1,543	-	2,899	4,698	-
Washington	-	11,019	-	16,446	16,694	-
Total		**476,163**	**206,781**		**374,961**	**268,994**

Note: In the Chicago, IL-IN 8-hour ozone nonattainment area, Cook County IL and Lake County, IN have separate attainment targets from those estimated for the remaining counties in the nonattainment area. Therefore, these two areas are shown separately in this exhibit.

Both New York and Philadelphia are in the region that is affected by the NO_x SIP Call, so those requirements provide the effective baseline for applying additional local controls in this analysis. Philadelphia makes more progress in achieving further NO_x emission reductions in 2010 than New York does largely because the Philadelphia area is able to reduce its EGU NOx emissions by about 30 thousand tons more than the New York area achieves in 2010. Non-EGU stationary source emission reductions are also slightly higher in Philadelphia than New York because the Philadelphia area has more NO_x beyond the SIP Call emission reductions available. These emission reductions are largely achieved at cement and glass manufacturing plants in the area surrounding the nonattainment area proper.

While mobile source controls applied by 2010 are able to reduce both VOC and NO_x emissions, there is less area-to-area variability in the emission reductions from this sector.

8-HOUR OZONE ANALYSIS – CALIFORNIA NONATTAINMENT AREAS

As mentioned in the previous section, no modeling results were available from EPA for estimating the VOC and NO_x emission reduction targets for California areas not attaining the 8-hour ozone NAAQS. Alternate methods were needed for estimating the needed ozone precursor emission reductions and associated costs to meet the 8-hour ozone NAAQS in California nonattainment areas. A large fraction of the State is classified as being nonattainment for 8-hour ozone. The Project Team's emissions and cost analysis approach was to identify expected needed ozone precursor emission reductions by area for the areas that are classified as serious or severe, with the likelihood that these areas will have the highest expected compliance costs. California areas that are classified as either serious or severe ozone nonattainment are: Sacramento Metro, San Joaquin Valley, and Los Angeles-South Coast Air Basin.[53] For this analysis, the San Joaquin Valley nonattainment area is divided into three sub-areas, reflecting different emission reduction targets required for the Northern, Central, and Southern regions of the valley.

The Project Team relied on modeling performed by each nonattainment area's air quality management district to estimate the required emission reductions for VOC and NO_x, incorporating both RFP requirements and reductions required to attain the 8-hour ozone NAAQS. A detailed description of how modeling results were translated into absolute emission reduction targets can be found in Appendix I.

Assuming that these serious or severe California nonattainment areas already had RACT controls applied in the base inventory, the Project Team applied I/M controls and additional local controls, following the same process as described in the previous section on non-California areas. Exhibits 8-4a and 8-4b compare the total emission reductions achieved with the estimated target reduction for each area.

[53] Analysis of the South Coast Air Basin incorporates emissions from the neighboring Coachella Valley subregion of the Riverside County nonattainment area, which is impacted by pollutant transport from the South Coast Air Basin and therefore under the purview of the South Coast Air Quality Management District.

EXHIBIT 8-4A. COMPARISON OF ATTAINMENT TARGETS WITH REDUCTIONS ACHIEVED VIA LOCAL MEASURES IN CALIFORNIA AREAS (2010)[54]

Area Name	VOC Reduction Target (tons)	VOC Reduced, Identified Measures (tons)	Remainder Unidentified Measures (tons)	NO_x Reduction Target (tons)	NO_x Reduced, Identified Measures (tons)	Remainder Unidentified Measures (tons)
Central San Joaquin Valley, CA	24,028	14,073	9,955	23,692	15,860	7,832
Los Angeles, CA	3,436	3,611	-	-	-	-
Northern San Joaquin Valley, CA	8,149	8,165	-	9,928	11,107	-
Sacramento, CA	16,022	16,252	-	21,091	21,152	-
Southern San Joaquin Valley, CA	19,185	19,456	-	31,506	31,608	-
Totals	**70,820**	**61,557**	**9,955**	**86,217**	**79,727**	**7,832**

[54] For the Central San Joaquin Valley nonattainment area, emission reductions incorporate controls applied to sources within 100 and 200 kilometers of the nonattainment area for VOC and NO_x emissions, respectively. Emission reductions for the other four nonattainment areas listed do not incorporate such controls because they reach their reduction targets solely with emission reductions from controls applied within the nonattainment areas themselves.

EXHIBIT 8-4B. COMPARISON OF ATTAINMENT TARGETS WITH REDUCTIONS ACHIEVED VIA LOCAL MEASURES IN CALIFORNIA AREAS (2020)[55]

Area Name	VOC Reduction Target (tons)	VOC Reduced, Identified Measures (tons)	Remainder Unidentified Measures (tons)	NO_x Reduction Target (tons)	NO_x Reduced, Identified Measures (tons)	Remainder Unidentified Measures (tons)
Central San Joaquin Valley, CA	26,877	15,880	10,997	8,591	9,889	-
Los Angeles, CA	166,349	37,529	128,820	182,161	39,843	142,318
Northern San Joaquin Valley, CA	9,941	9,948	-	(1,267)	-	-
Sacramento, CA	5,503	5,517	-	1,303	1,634	-
Southern San Joaquin Valley, CA	18,719	18,740	-	30,077	30,319	-
Totals	**227,389**	**87,613**	**139,818**	**220,865**	**80,387**	**142,318**

[55] For the Central San Joaquin Valley and Los Angeles nonattainment areas, emission reductions incorporate controls applied to sources within 100 and 200 kilometers of the nonattainment area for VOC and NO_x emissions, respectively. Emission reductions for the other three nonattainment areas listed do not incorporate such controls because they reach their reduction targets solely with emission reductions from controls applied within the nonattainment areas themselves

As indicated in Exhibit 8-4a, the modeled VOC and NO_x emission reductions for Central San Joaquin Valley were not sufficient to meet attainment. Exhibit 8-4b shows a significant increase in the amount of residual tons to be met by unidentified measures because sufficient control measures are not available to meet the very large emission reductions required in the South Coast Air Basin (Los Angeles) to attain the 8-hour ozone NAAQS in 2020. In both years, this shortfall in emissions reductions must be made up by unidentified controls.

Comparing the 2020 and 2010 attainment targets for the individual nonattainment areas shows that the required local reductions for the SJV and Sacramento areas are considerably lower in 2020 than in 2010. This occurs because the core scenarios (Federal and State rules) are expected to produce continuing emission reductions between 2010 and 2020, so the needed emission reductions to reach attainment emission levels in 2020 are lower than in 2010. A significant part of these 2010 to 2020 emission reductions for VOC and NO_x are achieved by emission and fuel standards applied to onroad vehicles and nonroad engines/vehicles.

CLEAN AIR VISIBILITY RULE ANALYSIS

The EPA rule aimed at addressing regional haze is commonly known as the Best Available Retrofit Technology rule, or BART rule, but will be referred to hereafter by its official EPA name: the Clean Air Visibility Rule, or CAVR (except that the widely used term "BART-eligible" will still be used herein).

The Project Team estimated the non-EGU NO_x and SO_2 emissions reductions and control costs using methods developed previously for the EPA analysis of the implementation of the CAVR. EGU emission reductions associated with CAVR are included in the core scenarios.

For the EPA analysis of the CAVR, EPA evaluated three possible scenarios of actions the states may take to comply with this rule. Of the three scenarios, this section 812 study uses the medium stringency option. The CAVR requirements of the regional haze rule apply to facilities built between 1962 and 1977 that have the potential to emit more than 250 tons per year of visibility impairing pollution. Those facilities fall into 26 categories, including utility and industrial boilers, and large industrial plants such as pulp mills, refineries and smelters. Many of these facilities have not previously been subject to federal pollution control requirements for these pollutants.

The two main data inputs used in this analysis are the 2020 control measure database developed using AirControlNET and a list of non-EGU BART-eligible sources previously developed by EPA which identify the potentially affected BART-eligible non-EGU sources. The control measure database contains a listing of control strategies and the resulting emission reductions, control costs, and annualized capital and operating and maintenance (O&M) costs at the facility-level for each control strategy.

For this analysis, the Project Team determined the NO_x and SO_2 control measure applicability, emissions reductions, and control costs for non-EGU BART-eligible sources for a scenario that limited the control set to a maximum average annualized cost of $4,000/ton. (See Pechan, 2005b). The $4,000/ton limit is the definition of the medium stringency option that was evaluated in the CAVR RIA. Note that the definition of what constitutes BART, which is determined on a case-by-case basis, could be a considerably different control level from what might be an appropriate cost per ton threshold in any nonattainment area plan. The results of this analysis are summarized in Exhibit 8-5 which shows the NO_x and SO_2 emissions reductions by State and by pollutant for 2020.

In practice, the states must consider a number of factors when determining what facilities will be covered by CAVR including: the cost of controls, the effect of controls on energy usage or any non-air quality environmental impacts, the remaining useful life of the equipment to be controlled, any existing controls in place, and the expected visibility improvement from controlling the emissions.

EXHIBIT 8-5. CLEAN AIR VISIBILITY RULE EMISSION REDUCTION RESULTS FOR 2020

State	NO_x Emission Reduction (tons)	SO_2 Emission Reduction (tons)
Alabama	14,229	12,780
Arizona	-	1,286
Arkansas	-	5,740
California	3,236	10,064
Colorado	3,662	4,972
Connecticut	83	158
Delaware	409	-
Florida	8,516	16,172
Georgia	10,405	12,545
Idaho	2,030	2,955
Illinois	5,700	4,132
Indiana	9,705	10,667
Iowa	5,118	12,577
Kansas	3,479	-
Kentucky	3,584	6,521
Louisiana	57,000	21,300
Maine	6,006	7,943
Maryland	1,192	-
Massachusetts	619	1,144
Michigan	8,682	12,793
Minnesota	4,809	4,988
Mississippi	9,403	3,729
Missouri	1,623	1,720
Montana	659	-
Nebraska	436	1,332
Nevada	449	-
New Hampshire	64	744
New Jersey	556	-
New Mexico	3,286	-
New York	2,250	2,822
North Carolina	4,650	5,961
Ohio	6,955	11,374
Oklahoma	4,806	2,189
Oregon	3,320	-
Pennsylvania	4,711	74

State	NO_x Emission Reduction (tons)	SO_2 Emission Reduction (tons)
Rhode Island	20	-
South Carolina	11,625	13,338
Tennessee	6,686	34,633
Texas	3,926	-
Washington	10,934	-
West Virginia	3,907	271
Wisconsin	1,733	20,156
Wyoming	5,460	4,209
TOTAL	**235,925**	**251,287**

$PM_{2.5}$ NAAQS ATTAINMENT ANALYSIS

On September 8, 2005, EPA proposed requirements that State and local governments have to meet as they implement the NAAQS for $PM_{2.5}$. The implementation rule stated that nonattainment area State Implementation Plans (SIPs) should include reasonably available control measure (RACM) and RACT control programs as well as show RFP. SIPs were due in April 2008 for $PM_{2.5}$ NAAQS attainment – three years after designation. There are 39 $PM_{2.5}$ nonattainment areas. The proposed rule requires States to meet the $PM_{2.5}$ standard by 2010.

EPA's proposed implementation of the $PM_{2.5}$ NAAQS presents different options that EPA might select for identifying which $PM_{2.5}$ precursors an area might need to control, proposed options for $PM_{2.5}$ classification, as well as options for RACT, RACM, and RFP (70 FR 71612). This analysis focuses on estimating the potential emission reductions in PM precursors following EPA's preferred approach at proposal, with a few exceptions noted below. Our approach can be summarized as follows:

1. $PM_{2.5}$ precursors are SO_2 and NO_x. States are not required to address ammonia as a $PM_{2.5}$ nonattainment plan precursor unless the State or EPA makes a technical demonstration that ammonia emissions from sources in the State significantly contribute to the $PM_{2.5}$ problem. EPA proposes that States are not required to address VOCs as $PM_{2.5}$ nonattainment precursors. (No ammonia or VOC controls were included in this $PM_{2.5}$ analysis.)

2. There is no separate RACT requirement if an area can demonstrate that it will be in attainment by 2010. Extension areas (i.e., those areas that cannot demonstrate attainment by 2010) apply RACT to affected sources in return for receiving the extension. The extension could be from one to five years past 2010. EPA's own evaluation of State SIPs for compliance with the RACT and RACM requirements will include comparisons of measures considered or adopted by other States. $PM_{2.5}$ controls will focus on upgrades to existing control technologies and compliance monitoring methods. RACT determinations are needed for PM precursors (SO_2 and NO_x).

3. No cost per ton threshold is specified. (EPA's proposed implementation rule says that their preferred approach is to not specify a cost per ton threshold,

which leaves areas discretion in how they might apply their own cost per ton thresholds. As a practical matter, a \$15,000 per ton upper limit is applied in this analysis. This approach is consistent with prior analyses, including the first 812 Prospective Study, but is updated to reflect information suggesting measures in the \$10,000 to \$15,000 cost per ton range have been widely adopted at the local level. The approach rests on the assumption that requirements where per ton costs exceed \$15,000 will motivate technological improvements or alternative or innovative measures to avoid incurring exorbitant control costs. In practice, the upper limit cost per ton threshold will differ by pollutant and geographic area according to the need to reduce certain pollutants per local source mixes and atmospheric conditions.

4. RACT controls must be in place by 2009.

5. For RACM, States are required to provide a demonstration that they have adopted all reasonably available measures needed to attain as expeditiously as practicable. Exhibit 8-6 summarizes emission reduction measures which were listed in the preamble to the proposed $PM_{2.5}$ implementation rule as potential RACM measures that should be considered by states. (This analysis includes as many of the measures in Exhibit 8-6 as matches were found with measures in AirControlNET. These assignments were made based on the judgment of the Project Team.)

EXHIBIT 8-6. $PM_{2.5}$ IMPLEMENTATION RULEEMISSION REDUCTION MEASURES -- POTENTIAL RACM

Measures
Stationary Source Measures
Stationary diesel engine retrofit, rebuild or replacement, with catalyzed particle filter
New or upgraded emission control requirements for direct $PM_{2.5}$ emissions at stationary sources (e.g., installation or improved performance of control devices such as a baghouse or electrostatic precipitator; revised opacity standard; improved compliance monitoring methods)
New or upgraded emission controls for $PM_{2.5}$ precursors at stationary sources (e.g., SO_2 controls such as wet or dry scrubbers, or reduced sulfur content in fuel)
Energy efficiency measures to reduce fuel consumption and associated pollutant emissions (either from local sources or distant power providers)
Mobile Source Measures
Onroad diesel engine retrofits for school buses and trucks using EPA-verified technologies
Nonroad diesel engine retrofit, rebuild or replacement, with catalyzed particle filter
Diesel idling programs for trucks, locomotive, and other mobile sources
Transportation control measures (including those listed in section 108(f) of the CAA as well as other TCMs), as well as other transportation demand management and transportation systems management strategies
Programs to reduce emissions or accelerate retirement of high emitting vehicles, boats, and lawn and garden equipment
Emissions testing and repair/maintenance programs for onroad vehicles
Emissions testing and repair/maintenance programs for nonroad heavy-duty vehicles and equipment
Programs to expand use of clean burning fuels
Prohibitions on the sale and use of diesel fuel that exceeds a high sulfur content
Low emissions specifications for equipment or fuel used for large construction contracts, industrial facilities, ship yards, airports, and public or private vehicle fleets
Opacity or other emissions standards for “gross-emitting” diesel equipment or vessels
Reduce dust from paved and unpaved roads
Area Source Measures
New open burning regulations and/or measures to improve program effectiveness

Measures
Smoke management programs to minimize emissions from forest and agricultural burning activities
Programs to reduce emissions from woodstoves and fireplaces
Controls on emissions from charbroiling or other commercial cooking operations
Reduced solvent usage or solvent substitution (particularly for organic compounds with 7 carbon atoms or more, such as toluene, xylene, and trimethyl benzene)
Reduce dust from construction activities and vacant disturbed areas

Area-specific SIP control measures were not available in time for this analysis. Therefore, the Project Team developed a representative model SIP control program based on available control measures in AirControlNET for primary $PM_{2.5}$, SO_2 and NO_x. This list of control measures is shown in Exhibit 8-7, which includes both RACT and RACM controls. Note that point source and EGU control measures in AirControlNET were applied only to sources with annual emissions greater than 100 tons, as suggested in the EPA proposed rule.

For this analysis, the Project Team estimated attainment costs and emissions reductions using the AirControlNET control measure dataset and applied the model control measures to sources in the nonattainment areas. The model SIP measure list was applied to all $PM_{2.5}$ nonattainment area counties, up to a maximum cost per ton of $15,000 for SO_2 and NO_x sources, as discussed above. This maximum cost per ton is applied on a source category-control measure combination basis. The cost and emissions analysis also includes estimates of the costs associated with the implementation of the mandatory control requirements in the nonattainment areas, such as NO_x RACT. Exhibits 8-8a and 8-8b provide the emission reductions by pollutant for the $PM_{2.5}$ NAAQS analysis for 2010 and 2020, respectively.

EXHIBIT 8-7. LIST OF PM NAAQS MODEL SIP CONTROL MEASURE

Source	Pollutant	Measure Name
Industrial Boilers - Coal	PM	Increased Monitoring Frequency (IMF) of PM Control
Industrial Boilers - Wood	PM	Increased Monitoring Frequency (IMF) of PM Control
Industrial Boilers - Oil	PM	Increased Monitoring Frequency (IMF) of PM Control
Commercial Institutional Boilers - Coal	PM	Increased Monitoring Frequency (IMF) of PM Control
Commercial Institutional Boilers - Wood	PM	Increased Monitoring Frequency (IMF) of PM Control
Commercial Institutional Boilers - Oil	PM	Increased Monitoring Frequency (IMF) of PM Control
Non-Ferrous Metals Processing - Copper	PM	Increased Monitoring Frequency (IMF) of PM Control
Non-Ferrous Metals Processing - Lead	PM	Increased Monitoring Frequency (IMF) of PM Control
Non-Ferrous Metals Processing - Zinc	PM	Increased Monitoring Frequency (IMF) of PM Control
Non-Ferrous Metals Processing - Aluminum	PM	Increased Monitoring Frequency (IMF) of PM Control
Non-Ferrous Metals Processing - Other	PM	Increased Monitoring Frequency (IMF) of PM Control
Ferrous Metals Processing - Coke	PM	Increased Monitoring Frequency (IMF) of PM Control
Ferrous Metals Processing - Ferroalloy Production	PM	Increased Monitoring Frequency (IMF) of PM Control
Ferrous Metals Processing - Iron & Steel Production	PM	Increased Monitoring Frequency (IMF) of PM Control
Ferrous Metals Processing - Gray Iron Foundries	PM	Increased Monitoring Frequency (IMF) of PM Control
Ferrous Metals Processing - Steel Foundries	PM	Increased Monitoring Frequency (IMF) of PM Control
Mineral Products - Cement Manufacture	PM	Increased Monitoring Frequency (IMF) of PM Control
Mineral Products - Coal Cleaning	PM	Increased Monitoring Frequency (IMF) of PM Control
Mineral Products - Stone Quarrying & Processing	PM	Increased Monitoring Frequency (IMF) of PM Control
Mineral Products - Other	PM	Increased Monitoring Frequency (IMF) of PM Control
Asphalt Manufacture	PM	Increased Monitoring Frequency (IMF) of PM Control
Chemical Manufacture	PM	Increased Monitoring Frequency (IMF) of PM Control
Electric Generation - Coal	PM	Increased Monitoring Frequency (IMF) of PM Control
Commercial Institutional Boilers - Solid Waste	PM	Increased Monitoring Frequency (IMF) of PM Control
Electric Generation - Coke	PM	Increased Monitoring Frequency (IMF) of PM Control
Electric Generation - Bagasse	PM	Increased Monitoring Frequency (IMF) of PM Control
Electric Generation - LPG	PM	Increased Monitoring Frequency (IMF) of PM Control
Electric Generation - Liquid Waste	PM	Increased Monitoring Frequency (IMF) of PM Control
Electric Generation - Natural Gas	PM	Increased Monitoring Frequency (IMF) of PM Control
Electric Generation - Oil	PM	Increased Monitoring Frequency (IMF) of PM Control
Electric Generation - Solid Waste	PM	Increased Monitoring Frequency (IMF) of PM Control
Electric Generation - Wood	PM	Increased Monitoring Frequency (IMF) of PM Control
Ferrous Metals Processing - Other	PM	Increased Monitoring Frequency (IMF) of PM Control
Industrial Boilers - Coke	PM	Increased Monitoring Frequency (IMF) of PM Control
Industrial Boilers - Solid Waste	PM	Increased Monitoring Frequency (IMF) of PM Control
Industrial Boilers - Coal	PM	CEM Upgrade and IMF of PM Controls
Industrial Boilers - Wood	PM	CEM Upgrade and IMF of PM Controls
Industrial Boilers - Oil	PM	CEM Upgrade and IMF of PM Controls

Source	Pollutant	Measure Name
Commercial Institutional Boilers - Coal	PM	CEM Upgrade and IMF of PM Controls
Commercial Institutional Boilers - Wood	PM	CEM Upgrade and IMF of PM Controls
Commercial Institutional Boilers - Oil	PM	CEM Upgrade and IMF of PM Controls
Non-Ferrous Metals Processing - Copper	PM	CEM Upgrade and IMF of PM Controls
Non-Ferrous Metals Processing - Lead	PM	CEM Upgrade and IMF of PM Controls
Non-Ferrous Metals Processing - Zinc	PM	CEM Upgrade and IMF of PM Controls
Non-Ferrous Metals Processing - Aluminum	PM	CEM Upgrade and IMF of PM Controls
Non-Ferrous Metals Processing - Other	PM	CEM Upgrade and IMF of PM Controls
Ferrous Metals Processing - Coke	PM	CEM Upgrade and IMF of PM Controls
Ferrous Metals Processing - Ferroalloy Production	PM	CEM Upgrade and IMF of PM Controls
Ferrous Metals Processing - Iron & Steel Production	PM	CEM Upgrade and IMF of PM Controls
Ferrous Metals Processing - Gray Iron Foundries	PM	CEM Upgrade and IMF of PM Controls
Ferrous Metals Processing - Steel Foundries	PM	CEM Upgrade and IMF of PM Controls
Mineral Products - Cement Manufacture	PM	CEM Upgrade and IMF of PM Controls
Mineral Products - Coal Cleaning	PM	CEM Upgrade and IMF of PM Controls
Mineral Products - Stone Quarrying & Processing	PM	CEM Upgrade and IMF of PM Controls
Mineral Products - Other	PM	CEM Upgrade and IMF of PM Controls
Asphalt Manufacture	PM	CEM Upgrade and IMF of PM Controls
Chemical Manufacture	PM	CEM Upgrade and IMF of PM Controls
Electric Generation - Coal	PM	CEM Upgrade and IMF of PM Controls
Commercial Institutional Boilers - Solid Waste	PM	CEM Upgrade and IMF of PM Controls
Electric Generation - Coke	PM	CEM Upgrade and IMF of PM Controls
Electric Generation - Bagasse	PM	CEM Upgrade and IMF of PM Controls
Electric Generation - LPG	PM	CEM Upgrade and IMF of PM Controls
Electric Generation - Liquid Waste	PM	CEM Upgrade and IMF of PM Controls
Electric Generation - Natural Gas	PM	CEM Upgrade and IMF of PM Controls
Electric Generation - Oil	PM	CEM Upgrade and IMF of PM Controls
Electric Generation - Solid Waste	PM	CEM Upgrade and IMF of PM Controls
Electric Generation - Wood	PM	CEM Upgrade and IMF of PM Controls
Ferrous Metals Processing - Other	PM	CEM Upgrade and IMF of PM Controls
Industrial Boilers - Coke	PM	CEM Upgrade and IMF of PM Controls
Industrial Boilers - Solid Waste	PM	CEM Upgrade and IMF of PM Controls
Agricultural Burning	PM	Bale Stack/Propane Burning
Residential Wood Combustion	PM	Education and Advisory Program
Sulfuric Acid Plants - Contact Absorber (99% Conversion)	SO2	Increase % Conversion to Meet NSPS (99.7)
Sulfuric Acid Plants - Contact Absorber (98% Conversion)	SO2	Increase % Conversion to Meet NSPS (99.7)
Sulfuric Acid Plants - Contact Absorber (97% Conversion)	SO2	Increase % Conversion to Meet NSPS (99.7)

Source	Pollutant	Measure Name
Sulfuric Acid Plants - Contact Absorber (93% Conversion)	SO2	Increase % Conversion to Meet NSPS (99.7)
Sulfur Recovery Plants - Elemental Sulfur (Claus: 2 Stage w/o control (92-95% removal))	SO2	Amine Scrubbing
Sulfur Recovery Plants - Elemental Sulfur (Claus: 2 Stage w/o control (92-95% removal))	SO2	Sulfur Recovery and/or Tail Gas treatment
Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage w/o control (95-96% removal))	SO2	Amine Scrubbing
Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage w/o control (95-96% removal))	SO2	Sulfur Recovery and/or Tail Gas treatment
Sulfur Recovery Plants - Elemental Sulfur (Claus: 4 Stage w/o control (96-97% removal))	SO2	Amine Scrubbing
Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage w/o control (96-97% removal))	SO2	Sulfur Recovery and/or Tail Gas treatment
Inorganic Chemical Manufacture	SO2	FGD
By-Product Coke Manufacturing (Coke Oven Plants)	SO2	Coke Oven Gas Desulfurization
Process Heaters (Oil and Gas Production Industry)	SO2	FGD
Primary Metals Industry	SO2	Sulfuric Acid Plant
Secondary Metal Production	SO2	FGD
Mineral Products Industry	SO2	FGD
Pulp and Paper Industry (Sulfate Pulping)	SO2	FGD
Petroleum Industry	SO2	FGD
Bituminous/Subbituminous Coal (Industrial Boilers)	SO2	FGD
Residual Oil (Industrial Boilers)	SO2	FGD
Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)	SO2	FGD
In-process Fuel Use - Bituminous/Subbituminous Coal	SO2	FGD
Lignite (Industrial Boilers)	SO2	FGD
Residual Oil (Commercial/Institutional Boilers)	SO2	FGD
Steam Generating Unit-Coal/Oil	SO2	FGD
Primary Lead Smelters - Sintering	SO2	Dual absorption
Primary Zinc Smelters - Sintering	SO2	Dual absorption
Bituminous/Subbituminous Coal (Industrial Boilers)	SO2	IDIS
Bituminous/Subbituminous Coal (Industrial Boilers)	SO2	SDA
Bituminous/Subbituminous Coal (Industrial Boilers)	SO2	Wet FGD
Lignite (Industrial Boilers)	SO2	IDIS
Lignite (Industrial Boilers)	SO2	SDA
Lignite (Industrial Boilers)	SO2	Wet FGD
Residual Oil (Industrial Boilers)	SO2	Wet FGD

Source	Pollutant	Measure Name
Residential Wood Combustion	PM	NSPS Compliant Wood Stove
Conveyorized Charbroilers	PM	Catalytic Oxidizer
Highway Vehicles - Gasoline	NOX	I/M - OBD Based for Section 812
Highway Vehicles - Heavy Duty Diesel Engines	NOX	Voluntary Diesel Retrofit Program: Section 812
Highway Vehicles - Heavy Duty Diesel Engines	PM	Onroad Retrofit/Scrappage
Highway Vehicles - Heavy Duty Diesel Engines	PM	Eliminate Long Duration Diesel Idling
Off-Highway Diesel Vehicles	PM	Off-Highway Diesel Engine Retrofit

EXHIBIT 8-8A. $PM_{2.5}$ NAAQS ATTAINMENT EMISSION REDUCTION RESULTS FOR 2010

	SO_2 Emission Reduction (tons)	NO_x Emission Reduction (tons)					$PM_{2.5}$ Emission Reduction (tons)				
Area Name	**Point**	**EGU**	**Point**	**Nonpoint**	**Onroad**	**Nonroad**	**EGU**	**Point**	**Nonpoint**	**Onroad**	**Nonroad**
Atlanta, GA	2,190	-	909	-	-	362	1,403	-	9	-	73
Baltimore, MD	-	-	1,034	-	425	106	341	-	-	93	21
Birmingham, AL	2,770	-	2,441	-	1,628	52	742	-	14	43	11
Canton-Massillon, OH	539	-	-	-	482	10	-	-	-	12	2
Charleston, WV	2,099	-	1,532	-	429	-	341	-	10	12	-
Chattanooga, AL-TN-GA	1,286	-	698	-	612	-	136	-	-	13	-
Chicago-Gary-Lake County, IL-IN	7,236	-	5,117	-	-	1,127	220	-	149	-	209
Cincinnati-Hamilton, OH-KY-IN	9,525	-	2,085	-	889	117	801	-	-	63	23
Cleveland-Akron-Lorain, OH	12,013	-	330	-	1,231	306	280	-	-	89	50
Columbus, OH	114	-	184	-	745	196	171	-	-	55	39
Dayton-Springfield, OH	2,031	-	1,187	-	542	78	51	-	-	29	14
Detroit-Ann Arbor, MI	5,982	-	2,798	-	2,176	374	923	-	-	160	74
Evansville, IN	-	-	-	-	-	68	963	-	-	-	12
Greensboro-Winston Salem-High Point, NC	-	-	146	-	402	63	-	-	123	30	14
Harrisburg-Lebanon-Carlisle, PA	-	-	-	-	144	26	-	-	-	32	4
Hickory, NC	-	-	-	-	119	-	295	-	-	8	-
Huntington-Ashland, WV-KY-OH	359	-	949	-	494	-	1,058	-	-	15	-
Indianapolis, IN	-	-	-	-	-	162	347	-	-	-	31
Johnstown, PA	-	-	-	-	202	-	353	-	10	9	-
Knoxville, TN	5,522	-	125	-	581	8	451	-	-	35	1
Lancaster, PA	-	-	-	-	95	31	-	-	-	22	5
Libby, MT	-	-	-	-	18	-	-	-	-	1	-
Liberty-Clairton, PA	455	-	148	-	436	167	48	-	13	32	35
Los Angeles-South Coast Air Basin, CA	-	-	4,026	-	6,839	2,287	-	-	1,469	390	465
Louisville, KY-IN	2,996	-	1,003	-	463	69	596	-	15	27	15
Macon, GA	582	-	397	-	-	-	329	-	-	-	-
Martinsburg, WV-Hagerstown, MD	799	-	1,244	-	241	-	-	-	-	17	-
New York-N. New Jersey-Long Island, NY-NJ-CT	549	-	518	-	2,212	2,157	320	-	231	397	445
Parkersburg-Marietta, WV-OH	5,916	-	580	-	243	-	233	-	-	6	-
Philadelphia-Wilmington, PA-NJ-DE	13,315	-	563	-	575	270	137	-	21	125	53
Pittsburgh-Beaver Valley, PA	5,916	-	1,739	-	1,064	41	883	-	10	51	8
Reading, PA	-	-	583	-	75	18	77	-	-	17	3
Rome, GA	4,129	-	1,450	-	-	-	150	-	-	-	-
San Joaquin Valley, CA	436	-	2,883	-	2,492	638	-	-	3,721	159	110
St. Louis, MO-IL	7,084	-	1,965	-	1,047	271	1,067	-	42	76	52
Steubenville-Weirton, OH-WV	311	-	851	-	110	-	524	-	-	3	-
Washington, DC-MD-VA	-	-	367	-	863	358	219	-	13	106	74
Wheeling, WV-OH	18,887	-	757	-	230	-	267	-	-	7	-
York, PA	6,752	-	531	-	77	26	324	-	-	18	4
TOTAL	**119,794**		**39,141**	**-**	**28,180**	**9,388**	**14,048**	**-**	**5,849**	**2,152**	**1,847**

EXHIBIT 8-8B. PM2.5 NAAQS ATTAINMENT EMISSION REDUCTION RESULTS FOR 2020

	SO_2 Emission Reduction (tons)	NO_x Emission Reduction (tons)					$PM_{2.5}$ Emission Reduction (tons)				
Area Name	**Point**	**EGU**	**Point**	**Nonpoint**	**Onroad**	**Nonroad**	**EGU**	**Point**	**Nonpoint**	**Onroad**	**Nonroad**
Atlanta, GA	2,259	-	564	-	-	85	782	-	-	-	20
Baltimore, MD	-	-	1,148	-	114	18	184	-	-	25	6
Birmingham, AL	3,015	-	2,712	-	1,423	11	531	-	11	11	2
Canton-Massillon, OH	328	-	-	-	417	-	-	-	-	3	-
Charleston, WV	2,068	-	1,662	-	284	-	316	-	-	2	-
Chattanooga, AL-TN-GA	1,253	-	589	-	537	-	144	-	-	3	-
Chicago-Gary-Lake County, IL-IN	2,636	-	5,559	-	-	338	222	-	161	-	65
Cincinnati-Hamilton, OH-KY-IN	8,609	-	1,911	-	99	10	642	-	-	16	2
Cleveland-Akron-Lorain, OH	10,273	-	298	-	133	90	223	-	-	22	14
Columbus, OH	100	-	256	-	85	58	190	-	-	14	13
Dayton-Springfield, OH	1,769	-	1,185	-	223	17	51	-	-	7	2
Detroit-Ann Arbor, MI	6,106	-	3,041	-	246	94	785	-	-	41	22
Evansville, IN	-	-	-	-	-	25	861	-	-	-	4
Greensboro-Winston Salem-High Point, NC	-	-	149	-	48	7	-	-	137	8	1
Harrisburg-Lebanon-Carlisle, PA	-	-	-	-	37	-	-	-	-	7	-
Hickory, NC	-	-	-	-	13	-	179	-	-	2	-
Huntington-Ashland, WV-KY-OH	242	-	1,030	-	164	-	930	-	-	2	-
Indianapolis, IN	-	-	-	-	-	41	261	-	-	-	9
Johnstown, PA	-	-	-	-	56	-	346	-	-	2	-
Knoxville, TN	5,486	-	189	-	101	-	183	-	-	9	-
Lancaster, PA	-	-	-	-	26	13	-	-	-	6	2
Liberty-Clairton, PA	403	-	157	-	50	40	48	-	10	8	12
Los Angeles-South Coast Air Basin, CA	-	-	4,592	-	1,334	827	-	-	1,625	222	199
Louisville, KY-IN	3,079	-	1,078	-	175	7	626	-	63	7	1
Macon, GA	573	-	422	-	-	-	329	-	-	-	-
Martinsburg, WV-Hagerstown, MD	-	-	1,370	-	171	-	-	-	-	4	-
New York-N. New Jersey-Long Island, NY-NJ-CT	583	-	558	-	1,033	529	276	-	216	103	132
Parkersburg-Marietta, WV-OH	5,827	-	546	-	136	-	233	-	-	2	-
Philadelphia-Wilmington, PA-NJ-DE	15,212	-	613	-	148	33	139	-	8	32	9
Pittsburgh-Beaver Valley, PA	6,079	-	1,872	-	510	4	486	-	-	12	1
Reading, PA	-	-	638	-	20	8	77	-	-	5	1
Rome, GA	4,103	-	1,508	-	-	-	77	-	-	-	-
San Joaquin Valley, CA	1,159	-	3,358	-	477	259	-	-	4,337	84	42
St. Louis, MO-IL	6,994	-	2,136	-	116	88	1,069	-	87	19	17
Steubenville-Weirton, OH-WV	141	-	980	-	36	-	457	-	-	-	-
Washington, DC-MD-VA	-	-	453	-	149	54	220	-	11	29	12
Wheeling, WV-OH	19,871	-	753	-	130	-	271	-	-	1	-
York, PA	5,981	-	500	-	21	8	118	-	-	5	1
TOTAL	**115,029**	**-**	**41,825**	**-**	**8,515**	**2,663**	**11,258**	**-**	**6,667**	**711**	**592**

Exhibits 8-8a and 8-8b also display the $PM_{2.5}$ NAAQS emission reduction results by nonattainment area. It shows that SO_2 emission reductions result from applying RACT-level controls to non-EGU point sources. The nonpoint source sector is unaffected because sources classified as nonpoint should be below the 100 ton per year RACT threshold (i.e., these are small point sources to which RACT or RACM controls are unlikely to be applied). Further controls are not applied to onroad and nonroad engines and vehicles because fuel sulfur limits have reduced these sector's SO_2 emissions to levels where further controls are not likely to be cost competitive with point source controls.

For $NO_{x,}$ no additional emission reductions are applied to EGUs in the $PM_{2.5}$ NAAQS analysis because it is expected that NO_x RACT is already being met by EGUs. However, NO_x RACT is applied to non-EGU point sources in areas that do not already have NOx RACT requirements. NO_x emission reductions observed for onroad vehicles in the $PM_{2.5}$ NAAQS analysis are usually attributable to measures selected to retrofit heavy-duty diesel engines and to reduce long duration diesel idling. Similarly, nonroad engine/vehicle associated emission reductions are for off-highway diesel engine retrofits.

$PM_{2.5}$ emission reductions for EGUs are usually related to adoption of control equipment efficiency improvements that are occurring because sources with ESPs or fabric filters are increasing the frequency of compliance monitoring or otherwise taking steps to improve the collection efficiency of their PM controls in place. Nonpoint source $PM_{2.5}$ emission reductions come from measures to increase the market share of New Source Performance Standard (NSPS) compliant wood stoves in residences. Onroad and nonroad engine/vehicle retrofit programs provide most of the $PM_{2.5}$ emission reductions observed for those sectors.

Note that this analysis was performed by defining nonattainment areas using county boundaries, because that is the way that the emission databases are organized. Some nonattainment areas include partial counties. If part of a county is in a nonattainment area, and the remainder of the county is in attainment, then the entire county is counted as part of the nonattainment area. If a county is part of two or more different nonattainment areas, then its emissions are assigned to the nonattainment area with the most severe nonattainment designation. As a result of the above, some $PM_{2.5}$ nonattainment areas do not show up in the results exhibit. For example, Riverside County, CA, is in three different $PM_{2.5}$ nonattainment areas. For this analysis, all of Riverside County's emissions are accounted for in the South Coast Air Basin nonattainment area.

Reductions associated with the $PM_{2.5}$ model SIP differ between 2010 and 2020 for two reasons. First, the 2020 case has CAVR-associated emission reductions applied prior to the emission reductions associated with $PM_{2.5}$ RACT and RACM. This leads to smaller NO_x and SO_2 emission reductions attributable to the model SIP in 2020. Second, the 2020 baseline differs from the 2010 baseline, primarily because of changes in economic activity and pollution control programs over this ten year period.

Exhibit 8-9 summarizes the national emission reductions associated with the 8-hour ozone NAAQS implementation, the CAVR rule, and the $PM_{2.5}$ NAAQS by pollutant.

EXHIBIT 8-9A. 2010 LOCAL MEASURES ANALYSIS SUMMARY NATIONAL EMISSION REDUCTIONS BY POLLUTANT (TONS)

	VOC	NO_x	SO_2	$PM_{2.5}$
8-Hour Ozone NAAQS	451,942	398,245	0	583
CAVR	0	0	0	0
$PM_{2.5}$ NAAQS	14,492	76,709	119,794	23,896
Total	**466,434**	**474,954**	**119,794**	**24,479**

EXHIBIT 8-9B. 2020 LOCAL MEASURES ANALYSIS SUMMARY NATIONAL EMISSION REDUCTIONS BY POLLUTANT (TONS)

	VOC	NO_x	SO_2	$PM_{2.5}$
8-Hour Ozone NAAQS	510,944	342,793	0	102
CAVR	0	235,925	251,287	0
$PM_{2.5}$ NAAQS	9,099	53,003	115,029	19,227
Total	**520,944**	**631,720**	**366,316**	**19,329**

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APPENDICES

APPENDIX A

STATE LEVEL EMISSION ESTIMATES

APPENDIX A | STATE LEVEL EMISSION ESTIMATES

This appendix summarizes State-level emissions by sector for each of the scenario years evaluated in this study. Tables are organized by sector, by year, and by scenario. The sectors are, in order: non-EGU point source, EGU point source, NONROAD model, onroad vehicles, and nonpoint sources.

Table A-1. Non-Electricity Generating Unit – State Emissions Summary (tons per year)
Year = 1990

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	58,115	75,941	170,073	120,042	66,939	13,869	3,586
AZ	12,669	44,002	11,477	60,121	16,179	2,984	4
AR	14,534	18,901	87,202	15,646	36,492	9,603	14,965
CA	124,511	174,389	105,024	53,258	52,153	16,742	14,816
CO	23,570	41,165	22,121	14,846	29,731	9,314	238
CT	12,657	15,510	8,204	17,801	12,789	682	58
DE	11,615	19,324	14,838	41,436	2,590	815	653
DC	247	1,172	258	2,418	135	8	11
FL	27,052	46,643	54,336	82,298	39,950	23,451	7,348
GA	45,494	61,653	157,038	81,006	40,302	15,705	13,811
ID	718	7,504	5,005	24,725	17,934	2,506	3
IL	66,278	39,303	112,639	274,651	208,838	15,126	11,348
IN	99,399	113,747	386,096	207,967	107,465	15,487	7,600
IA	10,544	24,754	6,416	81,832	9,203	7,650	8,111
KS	44,891	104,706	66,005	36,296	34,208	5,213	12,552
KY	118,463	32,341	87,728	40,897	18,283	10,701	1,152
LA	112,605	296,856	566,206	187,839	69,607	20,995	62,336
ME	20,996	38,656	116,550	58,579	15,911	4,188	114
MD	16,347	25,554	101,720	31,548	8,896	3,753	329
MA	19,480	20,809	5,141	23,275	4,095	1,811	92
MI	136,146	106,710	123,780	243,782	66,247	7,363	456
MN	51,258	59,193	75,358	31,681	61,293	3,860	993
MS	56,358	58,961	89,457	59,698	17,378	10,056	25,021
MO	59,881	27,281	96,849	118,781	90,594	7,629	21,869
MT	9,097	16,273	44,335	48,010	21,859	2,804	402
NE	11,128	9,367	3,229	8,138	26,571	804	6
NV	3,902	8,277	11,398	2,400	11,178	1,417	5
NH	8,159	3,856	20,973	8,090	1,701	345	21
NJ	108,281	71,819	19,653	65,080	17,510	2,455	514
NM	11,234	69,271	19,887	101,140	10,566	3,278	33
NY	158,897	75,206	31,538	233,992	78,045	4,427	242
NC	106,792	54,591	73,468	82,568	16,046	9,420	113
ND	3,888	13,849	3,641	44,528	4,996	1,105	13
OH	132,227	84,517	668,877	359,200	67,632	10,209	2,640
OK	42,888	91,130	55,210	76,885	30,522	5,334	16,416
OR	19,307	29,030	107,429	20,970	47,360	6,157	24
PA	134,089	188,598	984,744	163,985	61,868	11,498	5,885
RI	7,130	1,268	1,672	2,808	1,941	175	8
SC	49,974	55,402	45,235	91,584	18,990	8,154	55
SD	523	3,981	262	206	2,019	291	0
TN	129,831	100,785	95,651	175,748	29,491	21,697	79
TX	268,497	509,315	363,014	475,236	116,403	28,189	2,015
UT	13,220	27,132	47,605	54,976	15,513	3,131	1,119
VT	1,083	441	347	1,050	433	204	3
VA	97,532	82,616	32,787	103,333	27,908	9,860	696
WA	24,506	32,922	237,875	47,204	22,918	3,283	4,206
WV	60,170	72,268	229,110	42,367	18,960	8,040	408
WI	43,983	37,209	89,321	133,519	53,424	4,691	839
WY	19,202	39,252	10,621	39,827	3,743	8,779	402
National	**2,609,368**	**3,133,450**	**5,667,404**	**4,293,268**	**1,734,810**	**365,260**	**243,615**

Table A-2. Non-Electricity Generating Unit without CAAA Scenario – State Emissions Summary (tons per year) Year = 2000

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	68,257	87,742	189,332	163,272	83,197	13,869	2,853
AZ	21,203	62,313	17,212	48,942	18,942	2,984	4
AR	18,983	21,968	101,422	20,291	47,267	9,603	16,929
CA	145,190	203,482	110,730	42,155	61,721	16,742	13,453
CO	39,413	65,302	34,796	17,429	38,344	9,314	336
CT	15,060	13,993	9,136	9,644	13,026	682	19
DE	11,960	22,913	14,660	46,152	3,038	815	703
DC	284	1,658	423	5,060	259	8	5
FL	32,324	50,908	59,450	82,667	43,133	23,451	5,647
GA	55,808	60,710	169,458	71,358	43,482	15,705	10,569
ID	858	8,746	6,942	36,448	23,729	2,506	2
IL	75,689	40,918	131,642	272,816	251,747	15,126	12,123
IN	120,862	124,412	486,065	210,336	127,979	15,487	8,417
IA	13,775	27,329	7,881	100,234	10,792	7,650	6,645
KS	51,475	93,497	88,518	38,119	37,108	5,213	10,399
KY	141,715	37,459	117,898	45,396	20,438	10,701	2,055
LA	133,451	301,084	665,744	228,933	81,101	20,995	71,516
ME	22,074	37,844	122,832	60,711	16,081	4,188	126
MD	18,992	25,227	129,717	26,286	10,079	3,753	386
MA	23,231	20,142	5,274	13,564	3,890	1,811	56
MI	179,123	106,453	144,158	219,126	77,828	7,363	483
MN	63,562	70,189	85,635	35,462	72,748	3,860	1,032
MS	67,413	53,234	89,543	52,663	19,495	10,056	17,094
MO	71,574	30,998	105,769	142,831	107,424	7,629	17,899
MT	9,129	20,581	50,421	48,475	27,132	2,804	371
NE	13,075	13,322	3,643	9,894	28,828	804	11
NV	5,557	11,385	12,681	3,413	16,066	1,417	6
NH	9,126	4,050	19,824	7,556	1,592	345	21
NJ	110,542	63,087	18,247	21,723	10,579	2,455	220
NM	12,094	89,687	25,589	107,649	10,510	3,278	34
NY	172,026	67,388	40,288	201,587	77,429	4,427	165
NC	132,503	49,796	80,856	67,087	17,548	9,420	104
ND	6,225	22,268	5,456	59,450	5,285	1,105	5
OH	158,455	74,950	798,896	179,389	71,391	10,209	3,021
OK	41,882	75,682	52,063	84,729	36,407	5,334	18,253
OR	22,633	36,965	124,625	19,431	64,264	6,157	25
PA	138,723	171,352	1,014,840	140,227	67,088	11,498	3,851
RI	5,994	1,269	1,879	1,898	2,062	175	6
SC	60,585	57,383	50,006	87,952	20,550	8,154	57
SD	688	4,718	286	109	2,356	291	1
TN	150,295	101,723	97,095	153,087	32,193	21,697	76
TX	334,111	586,436	436,363	486,313	145,515	28,189	2,233
UT	17,304	35,337	66,189	52,052	21,152	3,131	1,426
VT	1,344	640	399	1,858	542	204	5
VA	112,206	79,509	35,546	89,396	31,557	9,860	845
WA	28,666	33,362	225,427	43,978	22,829	3,283	3,700
WV	68,671	68,180	239,136	33,461	24,225	8,040	495
WI	53,874	52,507	157,429	150,518	59,439	4,691	2,019
WY	19,613	41,208	15,431	58,459	4,305	8,779	429
National	**3,077,597**	**3,331,308**	**6,466,855**	**4,099,586**	**2,013,691**	**365,260**	**236,126**

Table A-3. Non-Electricity Generating Unit with CAAA Scenario – State Emissions Summary (tons per year)

Year = 2000

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	46,856	80,212	174,149	89,799	20,354	13,869	2,218
AZ	4,415	11,485	8,158	21,696	6,348	2,984	72
AR	32,002	27,934	51,440	19,038	14,101	9,603	1,255
CA	54,113	91,112	96,752	41,442	27,283	16,742	3,367
CO	90,704	41,757	28,350	7,600	18,490	9,314	86
CT	4,654	6,995	2,284	2,401	873	682	91
DE	4,653	6,358	9,071	40,648	1,059	815	153
DC	68	302	231	223	9	8	4
FL	36,898	43,662	81,733	53,968	31,913	23,451	3,021
GA	33,425	49,919	130,853	54,528	21,213	15,705	4,571
ID	2,109	11,339	23,734	17,597	4,570	2,506	1,074
IL	68,892	81,738	57,747	136,371	30,146	15,126	683
IN	55,875	79,877	364,118	100,435	27,095	15,487	3,133
IA	37,912	38,505	36,293	52,257	13,661	7,650	4,663
KS	26,477	71,246	75,084	10,803	10,053	5,213	60,102
KY	44,876	38,562	109,971	34,486	17,882	10,701	1,672
LA	78,361	199,173	126,312	172,861	28,451	20,995	7,851
ME	5,105	16,337	12,332	20,201	5,856	4,188	794
MD	5,695	21,917	94,342	34,255	6,301	3,753	222
MA	7,669	16,346	10,009	14,118	2,755	1,811	419
MI	39,680	78,329	65,280	59,828	14,468	7,363	976
MN	22,209	59,644	18,503	21,555	19,624	3,860	27,303
MS	43,180	60,175	54,482	36,517	19,665	10,056	1,405
MO	34,667	36,184	107,845	95,732	14,926	7,629	322
MT	6,803	16,565	29,396	13,271	6,185	2,804	265
NE	6,532	10,911	5,287	5,879	1,579	804	421
NV	1,596	11,173	7,501	1,321	3,236	1,417	234
NH	1,467	1,727	967	2,559	409	345	56
NJ	13,203	16,748	7,728	9,851	3,118	2,455	475
NM	15,122	59,571	32,024	18,166	3,980	3,278	44
NY	6,298	41,443	55,526	58,291	8,634	4,427	1,244
NC	61,213	42,422	50,447	45,192	13,294	9,420	1,484
ND	1,249	9,926	5,777	15,448	1,437	1,105	139
OH	29,535	65,199	237,918	111,496	14,737	10,209	6,364
OK	35,061	75,038	50,604	38,134	9,336	5,334	3,118
OR	14,514	14,756	33,992	5,249	9,819	6,157	787
PA	36,563	86,872	103,296	83,870	22,588	11,498	1,330
RI	1,880	2,039	1,499	2,652	291	175	47
SC	36,792	40,461	54,257	55,721	12,697	8,154	1,552
SD	2,430	4,765	4,070	1,480	608	291	50
TN	77,458	67,749	114,693	84,083	29,483	21,697	2,323
TX	149,573	338,064	284,414	247,601	40,088	28,189	2,297
UT	5,881	15,780	45,306	10,314	7,867	3,131	529
VT	1,077	354	213	875	295	204	16
VA	43,155	60,283	63,604	64,325	13,201	9,860	3,500
WA	12,439	24,427	38,043	24,291	5,614	3,283	826
WV	14,236	46,608	89,876	54,132	12,216	8,040	689
WI	31,018	38,837	34,013	66,971	7,902	4,691	397
WY	16,749	31,487	23,110	33,683	12,164	8,779	301
National	**1,402,343**	**2,292,311**	**3,112,631**	**2,193,213**	**597,875**	**365,260**	**153,944**

Table A-4. Non-Electricity Generating Unit without CAAA Scenario – State Emissions Summary (tons per year)
Year = 2010

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	70,180	85,883	198,579	173,598	84,746	14,690	3,321
AZ	26,125	70,165	20,487	37,933	22,744	3,570	4
AR	20,814	25,805	113,299	24,984	56,081	11,231	15,011
CA	173,850	211,260	125,174	54,057	68,350	19,884	15,622
CO	50,245	61,251	36,859	20,381	46,425	11,178	387
CT	16,965	17,469	10,541	15,253	14,808	770	41
DE	14,124	26,837	16,116	52,759	3,791	712	916
DC	279	1,949	488	5,677	286	8	5
FL	36,263	55,583	63,375	101,368	44,555	22,649	6,107
GA	71,952	80,628	222,341	91,745	57,868	17,579	11,383
ID	1,012	9,876	9,752	43,589	28,556	2,774	8
IL	83,033	41,374	127,777	298,678	270,517	16,563	12,136
IN	129,496	121,703	464,278	210,481	131,377	12,360	8,187
IA	14,794	29,464	8,748	109,171	12,188	8,876	6,871
KS	57,267	89,340	102,862	44,612	40,975	6,082	10,783
KY	173,207	56,429	199,651	55,864	30,063	11,649	2,377
LA	138,627	306,866	686,692	250,422	91,792	24,510	65,843
ME	21,239	49,712	133,449	95,224	19,104	4,832	217
MD	21,179	29,714	144,767	32,353	11,417	4,335	427
MA	25,329	28,476	6,677	32,292	5,345	2,018	127
MI	191,211	108,188	149,633	213,298	77,076	8,146	493
MN	75,215	73,587	99,292	42,424	82,656	4,523	1,218
MS	77,492	53,569	87,470	58,277	16,779	9,511	20,423
MO	75,026	35,231	102,893	165,934	108,950	8,084	18,512
MT	11,531	24,048	57,343	52,200	32,826	3,227	441
NE	14,197	14,052	3,972	12,523	29,912	987	11
NV	6,789	13,743	12,624	3,820	19,950	1,675	8
NH	8,979	5,666	16,258	17,172	2,294	385	42
NJ	132,318	68,409	20,569	25,414	11,332	2,907	256
NM	13,032	99,669	28,688	111,762	10,458	4,480	37
NY	192,908	70,056	42,883	209,257	80,469	4,861	149
NC	145,180	55,807	90,364	83,606	20,721	9,348	155
ND	8,018	23,164	6,217	59,292	2,398	1,208	6
OH	168,200	72,174	774,534	150,617	70,592	6,603	3,188
OK	58,099	82,949	54,929	100,605	43,212	6,128	16,483
OR	29,210	53,892	156,934	26,238	79,697	6,927	38
PA	149,311	173,143	1,053,419	147,539	70,708	12,867	4,069
RI	6,211	1,462	1,879	2,480	2,235	191	7
SC	70,231	63,194	55,502	107,223	24,573	7,643	75
SD	822	6,150	483	719	2,639	335	2
TN	164,675	105,265	101,117	168,884	35,549	22,137	81
TX	366,749	616,628	445,526	489,343	157,260	32,464	2,279
UT	19,673	39,311	73,419	52,442	23,979	3,695	1,595
VT	1,407	693	268	2,782	549	234	7
VA	131,568	86,234	41,377	98,798	36,256	10,257	925
WA	34,920	36,327	171,623	41,004	21,303	3,398	3,788
WV	80,889	65,693	264,222	37,132	26,858	8,985	534
WI	58,491	56,239	176,661	151,559	64,288	5,291	2,291
WY	24,464	51,546	26,240	104,482	5,305	11,179	572
National	**3,462,797**	**3,555,874**	**6,808,250**	**4,487,265**	**2,201,812**	**393,943**	**237,459**

Table A-5. Non-Electricity Generating Unit with CAAA Scenario – State Emissions Summary (tons per year)
Year = 2010

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	49,788	71,293	189,388	100,464	21,709	14,690	2,597
AZ	4,617	14,941	10,419	23,129	7,114	3,570	107
AR	36,561	31,410	63,117	21,029	16,417	11,231	1,950
CA	59,238	58,656	111,540	47,051	32,758	19,884	5,031
CO	112,952	46,561	34,322	8,626	13,638	11,178	142
CT	2,421	4,068	2,495	1,603	268	770	127
DE	4,643	1,362	10,107	11,237	828	712	169
DC	79	82	250	248	10	8	4
FL	40,747	46,697	94,663	39,103	31,528	22,649	3,920
GA	41,473	49,952	146,991	50,857	23,953	17,579	5,729
ID	1,776	13,003	29,700	19,407	4,931	2,774	1,223
IL	58,644	58,552	64,411	130,298	25,684	16,563	803
IN	55,080	54,482	298,726	89,773	19,547	12,360	3,379
IA	39,320	43,389	41,718	61,386	15,833	8,876	5,325
KS	27,710	77,783	92,665	12,925	11,799	6,082	64,749
KY	42,014	36,823	109,105	29,396	19,304	11,649	2,036
LA	81,961	184,625	123,363	155,359	33,173	24,510	8,924
ME	5,292	13,693	14,065	21,268	6,707	4,832	940
MD	5,120	9,741	107,450	36,287	4,048	4,335	251
MA	7,162	10,813	10,837	14,812	3,062	2,018	456
MI	34,596	80,668	68,664	60,641	11,449	8,146	1,191
MN	21,944	67,617	19,881	21,450	12,115	4,523	28,288
MS	44,883	49,995	61,167	37,848	19,482	9,511	966
MO	31,923	41,032	119,297	106,584	10,970	8,084	369
MT	7,541	19,794	32,714	10,504	5,089	3,227	291
NE	7,761	10,242	5,265	3,786	1,711	987	575
NV	1,790	13,369	8,838	1,584	3,387	1,675	409
NH	1,476	1,405	1,065	2,798	456	385	69
NJ	13,467	12,917	8,433	5,334	3,521	2,907	651
NM	15,964	67,647	37,849	7,607	4,653	4,480	56
NY	5,073	16,834	55,920	61,002	9,200	4,861	1,362
NC	60,658	37,449	57,551	46,395	11,288	9,348	1,791
ND	1,232	10,279	6,642	17,426	1,583	1,208	192
OH	22,075	42,147	187,438	53,662	8,017	6,603	7,014
OK	35,740	75,708	57,781	43,357	5,971	6,128	3,292
OR	12,914	17,135	39,566	5,909	10,788	6,927	1,203
PA	33,989	53,974	114,936	64,260	19,822	12,867	1,522
RI	1,809	1,153	1,684	2,887	316	191	65
SC	37,401	42,401	62,371	59,212	11,183	7,643	1,998
SD	2,139	6,152	4,986	1,767	706	335	69
TN	66,389	54,940	122,895	74,398	29,805	22,137	2,652
TX	161,970	243,325	330,354	254,568	46,599	32,464	3,517
UT	7,131	18,301	58,169	10,854	9,304	3,695	697
VT	1,221	242	242	952	338	234	23
VA	46,223	53,436	56,059	71,552	11,368	10,257	4,972
WA	13,747	26,098	39,454	23,341	3,563	3,398	1,005
WV	14,674	35,669	109,337	32,208	13,619	8,985	881
WI	31,653	29,213	39,482	64,399	8,859	5,291	474
WY	20,025	35,295	27,431	36,765	15,160	11,179	492
National	**1,434,004**	**1,992,361**	**3,290,804**	**2,057,305**	**582,635**	**393,943**	**173,946**

Table A-6. Non-Electricity Generating Unit without CAAA Scenario – State Emissions Summary (tons per year)
Year = 2020

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	74,474	94,370	200,861	177,344	92,294	15,780	3,387
AZ	33,795	82,355	26,290	44,725	28,183	4,182	4
AR	25,570	30,552	133,652	30,103	69,847	13,212	16,966
CA	218,316	226,895	141,377	55,786	78,180	23,746	16,671
CO	66,252	71,360	40,202	23,367	56,134	13,457	443
CT	19,772	19,964	12,823	16,315	16,807	896	40
DE	16,487	29,639	16,881	57,695	4,230	789	1,046
DC	301	2,121	546	6,158	321	9	7
FL	42,242	61,490	71,717	109,603	50,362	25,689	5,883
GA	82,832	89,460	251,971	102,338	66,383	20,429	10,960
ID	1,250	11,470	14,015	55,776	37,260	3,886	9
IL	95,051	44,736	133,602	323,784	299,360	18,130	13,371
IN	145,294	125,353	466,185	211,087	139,061	13,150	8,730
IA	16,992	30,237	9,389	109,217	13,337	10,141	7,028
KS	66,494	97,428	109,856	49,358	45,527	6,844	11,145
KY	196,668	61,943	219,350	60,051	32,312	12,772	2,701
LA	163,700	421,954	851,218	337,167	121,038	28,681	75,360
ME	21,761	49,445	135,162	92,681	19,523	5,182	209
MD	25,041	33,490	157,940	35,159	12,885	4,838	464
MA	29,266	33,343	8,018	33,642	6,023	2,233	127
MI	218,771	116,701	164,123	228,016	81,313	8,889	558
MN	87,146	79,922	112,205	47,303	89,809	5,235	1,366
MS	89,897	55,756	90,719	61,286	18,214	10,466	19,581
MO	84,233	38,471	111,435	193,621	119,311	8,977	18,928
MT	13,908	29,195	64,944	61,674	39,355	3,797	505
NE	15,947	15,172	4,130	13,538	32,461	1,205	12
NV	8,560	16,228	14,748	4,640	24,455	2,024	9
NH	10,336	5,736	17,454	16,578	2,313	421	42
NJ	156,196	77,959	23,266	26,805	12,266	3,456	274
NM	14,684	116,257	33,947	132,604	11,650	6,139	42
NY	215,672	74,796	51,834	213,495	88,383	5,253	152
NC	167,116	65,382	104,814	91,908	24,470	10,759	172
ND	8,793	25,064	6,686	64,910	2,704	1,318	6
OH	186,209	78,172	790,361	141,174	76,558	7,166	3,443
OK	75,520	95,862	62,614	111,438	52,435	7,285	18,588
OR	35,195	60,935	182,259	19,260	91,308	7,617	25
PA	163,429	184,134	1,057,544	153,378	77,984	14,138	3,872
RI	6,934	1,595	1,752	2,553	2,228	208	7
SC	83,694	72,031	63,851	116,073	28,418	8,740	82
SD	979	6,807	520	716	2,837	369	2
TN	182,339	112,709	105,048	176,662	39,407	24,579	92
TX	421,598	678,024	511,831	538,876	185,354	38,225	2,697
UT	23,259	45,037	75,837	55,219	28,153	4,395	1,739
VT	1,681	694	290	2,678	551	268	6
VA	155,547	100,393	48,922	107,131	41,503	11,954	1,023
WA	42,306	40,256	169,945	40,360	23,093	4,254	4,019
WV	94,257	70,390	279,734	41,051	29,283	9,865	579
WI	65,993	57,757	199,396	157,058	70,165	5,875	2,619
WY	27,442	58,237	30,417	120,173	6,058	14,246	647
National	**3,999,199**	**3,997,276**	**7,381,679**	**4,871,531**	**2,491,106**	**451,169**	**255,636**

Table A-7. Non-Electricity Generating Unit with CAAA Scenario – State Emissions Summary (tons per year) Year = 2020

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	54,135	66,747	198,939	93,796	23,426	15,780	2,877
AZ	7,231	15,872	11,859	27,146	8,970	4,182	174
AR	45,097	36,743	76,752	17,513	19,258	13,212	3,004
CA	72,724	80,403	129,583	43,171	39,410	23,746	7,627
CO	136,396	49,830	38,248	4,751	26,782	13,457	231
CT	2,681	4,822	2,850	1,628	294	896	176
DE	5,681	1,470	11,007	11,655	917	789	196
DC	88	92	279	280	11	9	5
FL	47,795	44,863	107,291	26,081	35,532	25,689	5,409
GA	50,457	46,045	166,288	43,148	27,623	20,429	7,208
ID	2,254	13,558	38,169	25,480	6,681	3,886	1,806
IL	66,090	62,399	69,962	130,986	27,951	18,130	947
IN	62,290	51,394	307,416	85,148	20,483	13,150	3,679
IA	45,729	41,560	45,554	52,127	17,956	10,141	6,125
KS	31,165	81,985	112,561	14,500	13,188	6,844	68,970
KY	45,715	38,328	118,253	24,845	21,039	12,772	2,460
LA	91,685	151,798	140,117	167,563	38,825	28,681	10,311
ME	5,638	9,172	15,138	14,734	7,174	5,182	1,032
MD	6,094	11,284	117,701	38,127	4,470	4,838	282
MA	8,335	12,346	12,219	14,689	3,376	2,233	509
MI	39,766	85,612	77,274	49,340	12,232	8,889	1,472
MN	25,329	69,085	21,878	17,627	13,617	5,235	30,139
MS	50,308	48,397	65,773	33,403	21,499	10,466	1,073
MO	36,501	44,248	131,926	123,230	12,124	8,977	436
MT	8,945	22,699	37,790	18,529	8,401	3,797	410
NE	9,187	11,342	6,223	2,949	2,095	1,205	757
NV	2,222	15,608	10,334	1,864	4,553	2,024	568
NH	1,762	1,591	1,154	2,260	497	421	81
NJ	16,496	15,368	9,599	6,213	4,170	3,456	875
NM	18,755	70,765	40,774	22,034	7,227	6,139	67
NY	5,544	18,014	59,558	58,348	10,159	5,253	1,463
NC	68,262	37,932	64,183	44,911	12,990	10,759	2,125
ND	1,346	11,450	7,512	18,885	1,735	1,318	257
OH	24,650	38,904	191,510	43,504	8,702	7,166	8,306
OK	38,229	82,218	66,179	47,238	7,162	7,285	3,878
OR	14,252	16,336	44,887	6,481	11,595	7,617	1,853
PA	37,207	55,225	126,436	66,537	21,898	14,138	1,754
RI	2,125	1,329	2,052	3,089	342	208	89
SC	43,504	35,984	70,507	50,760	12,694	8,740	2,572
SD	2,320	7,095	5,622	1,930	768	369	93
TN	70,633	53,392	130,243	40,196	32,915	24,579	2,992
TX	183,305	255,632	381,382	281,108	55,135	38,225	5,371
UT	9,113	20,211	66,258	11,892	11,028	4,395	943
VT	1,455	263	266	1,011	386	268	31
VA	53,136	63,709	63,683	82,126	13,336	11,954	7,260
WA	16,317	20,055	42,085	26,690	7,513	4,254	1,243
WV	17,996	37,722	157,980	41,634	14,937	9,865	1,185
WI	36,030	29,240	43,700	39,234	9,764	5,875	549
WY	23,711	32,492	30,482	40,666	19,018	14,246	799
National	**1,645,687**	**2,022,628**	**3,677,434**	**2,021,052**	**681,858**	**451,169**	**201,670**

Table A-8. Electricity Generating Unit – State Emissions Summary (tons per year)

Year = 1990

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	774	187,320	6,681	528,639	16,783	11,526	
AZ	562	72,730	4,967	119,900	13,606	7,044	
AR	443	39,524	4,205	69,160	4,637	3,625	
CA	587	110,602	9,419	7,796	1,319	1,155	
CO	562	88,848	4,822	86,983	6,688	5,462	
CT	463	22,669	1,873	53,014	3,009	2,050	
DE	139	23,726	1,009	46,990	1,537	1,173	
DC	24	704	84	2,524	86	68	
FL	2,148	285,786	14,472	645,930	20,055	15,819	
GA	981	228,804	8,411	875,451	18,974	13,305	
ID	0	0	0	0	0	0	
IL	1,023	259,728	8,640	899,210	13,392	10,312	
IN	1,741	421,755	15,011	1,511,021	26,693	20,319	
IA	544	78,309	4,798	180,529	6,406	4,900	
KS	552	69,370	5,029	87,679	6,766	4,937	
KY	1,079	345,009	9,259	905,632	24,895	14,114	
LA	643	85,773	8,804	98,711	5,551	4,220	
ME	106	3,701	368	11,502	385	314	
MD	514	117,577	3,652	282,451	6,620	4,887	
MA	878	92,286	4,652	232,286	5,203	4,129	
MI	1,085	205,587	9,324	375,772	17,623	12,637	
MN	606	83,138	5,346	84,413	8,317	6,369	
MS	218	48,511	2,348	119,115	2,508	1,947	
MO	852	193,776	7,407	787,810	10,937	8,671	
MT	330	31,554	2,836	17,922	6,936	4,813	
NE	284	32,958	2,472	50,534	3,019	2,387	
NV	288	48,790	2,684	55,779	6,699	3,531	
NH	150	30,242	776	68,508	1,154	898	
NJ	258	65,840	2,010	77,149	2,060	1,798	
NM	552	95,191	5,044	64,104	11,897	7,762	
NY	2,264	174,121	14,796	416,770	12,641	10,065	
NC	633	204,850	5,433	336,450	15,118	8,836	
ND	756	100,553	6,575	124,611	7,575	5,880	
OH	1,710	534,056	14,664	2,241,092	31,586	23,563	
OK	644	89,904	7,294	101,852	6,281	4,870	
OR	30	2,837	256	4,936	313	246	
PA	1,619	425,200	13,076	1,213,386	42,316	23,536	
RI	15	1,966	144	1,092	43	35	
SC	325	96,471	2,861	167,416	6,868	4,899	
SD	82	19,148	707	31,188	638	459	
TN	726	236,504	6,230	796,526	35,809	12,059	
TX	3,871	452,176	45,164	462,390	61,713	42,939	
UT	476	71,108	4,084	32,051	7,778	5,818	
VT	1	189	14	0	1	1	
VA	333	84,042	2,650	158,626	6,044	4,081	
WA	171	16,915	1,468	58,741	2,917	1,770	
WV	1,052	335,023	9,030	968,612	19,266	13,941	
WI	640	96,248	5,769	284,855	8,202	6,212	
WY	828	99,413	7,099	84,596	11,798	8,291	
National	**34,558**	**6,410,533**	**303,713**	**15,831,702**	**530,663**	**357,674**	

Table A-9. Electricity Generating Unit without CAAA Scenario– State Emissions Summary(tons per year)

Year = 2000

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	1,082	285,989	9,741	630,303	29,110	24,772	10
AZ	704	92,835	10,518	133,498	9,436	7,327	43
AR	380	36,207	3,519	66,560	2,395	1,992	7
CA	2,334	35,806	47,309	11,645	4,990	4,891	1,030
CO	566	108,420	8,968	115,149	3,775	3,254	5
CT	206	23,136	10,356	20,702	956	818	45
DE	50	13,853	569	23,540	3,455	2,243	0
DC	0	0	0	0	0	0	0
FL	1,760	282,948	37,009	631,197	26,147	19,905	311
GA	1,180	286,129	10,744	958,571	36,389	30,432	11
ID	39	1,325	1,503	0	121	121	0
IL	1,816	384,869	12,291	1,339,726	19,408	17,844	12
IN	1,906	521,180	14,995	1,702,996	54,984	44,945	17
IA	528	92,678	4,445	172,075	5,088	4,173	5
KS	669	89,149	5,186	77,738	5,938	4,846	6
KY	1,454	462,826	13,903	1,208,741	32,019	25,216	12
LA	526	50,385	5,743	118,952	3,145	2,742	8
ME	138	8,620	5,739	3,846	398	386	41
MD	445	141,201	7,514	339,857	23,314	21,805	4
MA	621	75,803	9,358	145,928	4,925	4,182	306
MI	1,431	268,463	13,207	465,965	27,521	22,279	13
MN	639	97,511	4,885	91,076	16,190	11,772	5
MS	212	42,642	2,944	122,411	3,511	2,774	2
MO	1,489	304,162	10,948	829,941	26,494	24,581	11
MT	312	37,501	2,592	19,089	7,470	4,706	3
NE	422	55,502	3,337	69,787	2,386	1,964	4
NV	359	55,879	5,630	78,938	4,552	3,667	6
NH	94	35,916	505	55,914	2,723	2,610	1
NJ	198	69,604	3,231	76,133	5,151	4,784	1
NM	444	83,722	4,239	38,112	9,381	6,375	11
NY	995	122,626	22,561	240,724	17,368	15,997	208
NC	1,027	349,310	9,936	548,470	32,110	26,740	10
ND	775	103,589	6,608	195,658	7,759	6,582	6
OH	1,845	662,269	15,469	2,765,359	85,106	75,429	17
OK	826	97,213	19,598	130,210	12,019	10,998	40
OR	189	11,370	5,467	9,857	855	769	1
PA	1,579	489,249	14,017	1,182,237	72,426	65,083	15
RI	38	957	1,500	0	121	121	0
SC	473	147,052	4,098	222,945	19,948	15,781	4
SD	100	20,955	476	33,828	198	187	1
TN	880	317,476	7,096	741,802	21,040	19,107	8
TX	5,467	433,125	77,675	633,659	36,154	27,406	941
UT	404	73,848	3,378	35,157	5,311	4,145	4
VT	0	22	8	0	1	1	0
VA	463	130,483	7,142	224,072	13,710	11,955	4
WA	286	27,950	5,498	68,012	3,086	2,549	2
WV	1,393	463,927	12,262	1,202,946	36,334	29,577	13
WI	837	133,093	7,221	285,118	8,352	7,395	7
WY	659	105,227	5,493	78,218	8,428	7,059	6
National	**40,238**	**7,734,001**	**496,431**	**18,146,659**	**751,696**	**634,288**	**3,217**

Table A-10. Electricity Generating Unit with CAAA Scenario– State Emissions Summary (tons per year) Year = 2000

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	1,086	167,467	9,818	559,925	28,433	24,157	11
AZ	750	79,291	10,988	47,637	9,880	7,572	33
AR	493	40,659	4,435	77,159	3,123	2,596	8
CA	2,287	38,875	46,221	3,901	4,897	4,798	1,012
CO	577	67,880	9,121	111,530	3,791	3,257	5
CT	211	10,634	10,518	15,227	969	831	45
DE	84	10,006	863	13,531	6,628	3,833	1
DC	0	0	0	0	0	0	0
FL	1,774	190,751	37,522	200,700	25,320	19,426	316
GA	1,124	150,203	10,294	573,241	34,192	28,639	11
ID	39	1,326	1,504	0	121	121	0
IL	2,125	196,082	14,120	362,667	19,405	17,564	15
IN	1,925	287,651	14,971	852,132	49,146	39,481	16
IA	598	63,741	5,156	119,119	5,698	4,598	5
KS	757	82,366	5,845	77,691	6,550	5,402	6
KY	1,465	223,728	13,521	572,876	31,060	24,434	12
LA	537	49,567	5,847	97,429	3,218	2,803	8
ME	158	5,360	6,243	5,244	441	428	47
MD	361	66,743	4,625	226,687	19,439	18,156	3
MA	515	37,214	8,973	91,182	4,619	3,885	179
MI	1,369	157,983	13,024	386,754	26,721	21,746	13
MN	678	80,031	5,235	107,507	18,723	13,599	6
MS	247	31,558	3,991	91,061	3,765	2,975	2
MO	1,702	169,687	12,403	303,764	27,668	25,623	13
MT	309	37,261	2,572	19,037	7,370	4,611	3
NE	404	45,775	3,257	69,023	2,385	1,962	4
NV	366	45,915	5,699	73,684	4,582	3,689	6
NH	94	7,187	513	50,452	2,724	2,610	1
NJ	182	21,004	2,993	62,031	4,636	4,304	1
NM	512	72,511	4,485	51,880	11,225	7,773	12
NY	1,052	77,205	23,603	212,391	16,713	15,495	265
NC	982	163,709	10,148	526,767	30,619	25,537	9
ND	684	60,402	5,786	168,298	7,030	5,984	6
OH	1,823	399,799	15,243	1,186,050	79,233	69,465	17
OK	830	79,504	19,636	121,139	12,022	11,002	43
OR	189	11,808	5,502	9,857	857	772	1
PA	1,456	208,104	12,983	752,903	63,813	57,141	14
RI	64	1,894	2,515	0	203	203	0
SC	494	58,675	4,282	242,458	19,725	15,644	5
SD	100	13,309	476	11,124	198	187	1
TN	840	142,893	6,784	392,933	19,720	17,812	7
TX	5,509	225,543	78,300	631,100	36,212	27,464	966
UT	405	58,385	3,387	50,167	5,257	4,106	4
VT	1	81	30	0	2	2	0
VA	475	78,514	8,307	228,372	13,713	11,989	4
WA	287	26,840	5,556	32,141	3,090	2,554	2
WV	1,387	282,518	12,198	773,366	36,370	29,678	12
WI	844	87,079	7,721	175,768	8,295	7,342	7
WY	731	79,262	6,092	81,492	8,915	7,386	7
National	**40,882**	**4,493,981**	**503,306**	**10,819,399**	**728,719**	**610,638**	**3,162**

Table A-11. Electricity Generating Unit without CAAA Scenario – State Emissions Summary(tons per year)
Year = 2010

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	1,318	309,096	16,736	639,259	31,626	26,968	11
AZ	1,079	100,463	23,443	140,076	12,545	10,119	6
AR	547	50,011	5,898	80,856	3,373	2,821	7
CA	919	40,900	34,090	11,855	3,630	3,530	1
CO	626	110,037	10,200	111,190	3,956	3,386	5
CT	127	17,257	9,167	24,789	874	733	1
DE	74	17,421	1,163	29,329	4,455	2,891	1
DC	1	35	26	0	2	2	0
FL	1,736	271,397	45,668	632,270	27,585	21,168	55
GA	1,618	324,165	20,157	1,023,606	41,947	34,840	13
ID	30	1,127	1,156	0	93	93	0
IL	1,987	407,191	13,732	1,373,192	22,487	20,681	14
IN	2,298	577,476	19,565	1,788,603	61,526	49,633	19
IA	793	132,318	7,164	194,551	10,084	8,601	7
KS	801	108,866	6,135	86,136	7,057	5,827	7
KY	1,595	501,568	16,090	1,267,681	36,224	28,763	13
LA	656	53,419	10,246	124,416	3,621	3,198	8
ME	48	3,100	3,907	3,915	237	224	0
MD	487	152,399	9,863	366,995	24,719	23,062	4
MA	486	76,033	11,858	109,912	4,854	4,108	69
MI	1,526	281,407	14,937	473,113	28,771	23,380	14
MN	745	113,265	5,830	104,812	19,909	14,471	6
MS	315	61,040	4,592	148,220	4,794	3,792	2
MO	1,707	325,717	12,667	680,220	28,811	26,644	13
MT	324	38,525	2,912	19,626	7,664	4,856	3
NE	443	58,393	3,523	71,175	2,489	2,051	4
NV	449	60,683	8,492	80,181	4,961	4,032	3
NH	168	37,254	3,343	56,920	3,001	2,885	1
NJ	305	96,715	6,076	95,535	6,772	6,252	2
NM	434	84,207	3,765	38,798	9,505	6,444	7
NY	753	108,902	21,006	237,181	17,547	16,152	11
NC	1,355	441,741	13,952	715,840	41,810	34,898	13
ND	788	105,282	6,718	199,124	7,900	6,704	6
OH	2,056	710,797	18,438	2,927,691	92,997	82,488	19
OK	993	98,127	26,376	132,823	12,751	11,712	29
OR	257	13,616	8,098	10,034	1,074	987	1
PA	1,844	534,178	19,179	1,196,541	77,856	69,999	16
RI	46	719	1,777	0	143	143	0
SC	637	170,949	7,782	252,155	22,379	17,781	5
SD	109	22,912	507	37,069	215	203	1
TN	897	325,241	6,979	763,241	21,799	19,819	8
TX	5,312	396,096	84,536	644,463	37,131	28,226	582
UT	423	77,368	3,523	36,439	5,593	4,360	4
VT	0	14	5	0	0	0	0
VA	640	156,970	12,497	270,511	17,211	15,117	5
WA	390	32,435	9,451	69,321	3,452	2,906	2
WV	1,452	484,112	12,705	1,245,710	38,406	31,352	13
WI	981	149,874	9,795	263,824	9,645	8,541	8
WY	759	108,662	6,325	88,335	9,171	7,599	7
National	**43,333**	**8,349,482**	**602,048**	**18,867,532**	**834,655**	**704,443**	**1,023**

Table A-12. Electricity Generating Unit with CAAA Scenario – State Emission Summary (tons per year)
Year = 2010

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	1,272	56,820	16,392	375,192	24,201	18,939	10
AZ	1,090	79,996	23,237	54,118	12,760	10,197	6
AR	676	31,930	10,632	82,416	3,811	3,248	7
CA	903	12,319	33,461	5,066	3,582	3,480	1
CO	634	69,070	10,490	91,838	3,980	3,410	5
CT	124	5,568	9,030	3,901	833	663	1
DE	111	2,047	1,341	45,132	8,147	4,668	1
DC	1	35	26	0	2	2	0
FL	1,691	63,182	45,776	167,154	25,699	19,283	9
GA	1,599	98,880	19,926	432,798	33,474	24,733	13
ID	30	663	1,171	0	95	95	0
IL	2,239	63,864	15,279	235,022	16,774	14,321	16
IN	2,181	96,259	19,110	332,276	43,181	30,726	18
IA	774	53,987	7,014	163,573	9,926	8,483	7
KS	816	90,207	6,221	80,070	7,152	5,917	7
KY	1,597	98,224	16,364	351,277	33,053	25,304	13
LA	632	35,540	9,276	99,182	3,543	3,120	8
ME	47	1,803	3,859	5,338	233	220	0
MD	481	8,900	8,074	55,567	8,427	6,294	4
MA	469	19,748	12,744	17,391	3,639	2,901	16
MI	1,505	92,145	14,882	392,452	28,269	22,045	14
MN	675	39,527	5,587	93,709	19,318	14,181	6
MS	341	31,166	5,589	85,626	4,874	3,872	3
MO	1,749	70,545	12,876	269,140	29,045	26,027	13
MT	322	38,465	2,897	22,474	7,650	4,845	3
NE	446	49,378	3,544	72,333	2,496	2,057	4
NV	434	46,373	8,206	30,826	4,886	3,973	3
NH	163	2,774	3,306	7,289	981	883	1
NJ	315	7,751	6,257	49,719	6,712	5,895	2
NM	514	73,563	4,436	52,884	11,416	7,902	8
NY	720	21,758	21,116	101,188	14,800	13,425	3
NC	1,292	58,786	13,357	266,539	29,422	22,497	12
ND	758	68,364	9,711	112,044	7,142	6,050	6
OH	2,114	91,067	20,678	326,054	47,224	33,874	19
OK	998	78,986	26,488	117,565	12,760	11,721	31
OR	259	11,035	8,181	10,034	1,081	994	1
PA	1,746	68,857	19,066	266,829	42,199	33,141	15
RI	44	648	1,719	0	139	139	0
SC	615	37,735	7,310	175,823	20,128	15,647	5
SD	109	14,541	507	12,085	215	203	1
TN	801	38,283	6,186	230,590	16,215	13,903	7
TX	4,900	151,606	93,158	399,621	37,078	28,280	488
UT	422	60,744	3,519	52,915	5,574	4,345	4
VT	0	14	5	0	0	0	0
VA	606	38,846	12,458	147,139	13,656	11,709	5
WA	390	25,802	9,463	12,236	3,453	2,907	2
WV	1,419	65,827	12,434	222,575	30,677	22,846	13
WI	966	45,516	9,855	161,474	9,579	8,507	8
WY	678	81,171	5,647	76,985	8,652	7,244	6
National	**42,664**	**2,300,315**	**617,860**	**6,365,458**	**658,151**	**515,115**	**822**

Table A-13. Electricity Generating Unit without CAAA Scenario – State Emission Summary (tons per year)
Year = 2020

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	1,533	321,642	24,778	629,253	32,492	27,795	13
AZ	1,285	109,398	30,704	136,580	13,383	10,813	6
AR	637	52,989	9,132	82,416	3,690	3,127	7
CA	1,557	72,160	59,026	11,855	5,643	5,542	0
CO	674	111,829	12,007	111,123	4,178	3,604	5
CT	139	17,357	9,617	24,789	910	770	1
DE	73	18,513	993	31,347	4,764	3,082	1
DC	17	1,816	204	629	708	674	0
FL	2,088	287,611	61,263	637,426	28,847	22,430	9
GA	1,990	342,102	34,612	1,032,735	43,131	36,024	14
ID	33	1,311	1,307	-	105	105	0
IL	2,250	427,699	17,955	1,252,427	23,828	21,922	15
IN	2,413	582,113	22,332	1,635,482	62,416	50,274	20
IA	871	142,261	8,772	200,226	11,095	9,497	7
KS	849	113,034	7,502	86,298	7,256	6,021	7
KY	1,652	512,256	17,530	1,294,604	37,362	29,701	13
LA	746	55,956	13,849	124,416	3,911	3,489	5
ME	59	3,735	4,328	3,915	271	258	0
MD	712	178,528	12,927	383,395	34,044	31,886	6
MA	441	77,314	12,170	96,268	4,781	4,037	2
MI	1,760	309,095	18,686	495,262	36,117	30,199	16
MN	784	118,038	6,426	115,783	21,215	15,430	7
MS	484	65,993	11,182	123,660	5,325	4,324	2
MO	1,778	332,881	14,522	630,371	29,646	27,424	13
MT	328	38,757	3,017	19,861	7,696	4,879	3
NE	446	58,758	3,632	71,490	2,501	2,063	4
NV	486	62,495	9,897	80,206	5,080	4,149	3
NH	197	38,631	4,468	43,766	3,092	2,976	1
NJ	340	104,083	7,120	111,212	7,252	6,694	2
NM	482	86,458	5,670	38,798	9,658	6,598	7
NY	836	113,181	22,668	251,522	18,178	16,783	4
NC	1,514	450,349	18,431	720,875	42,734	35,804	13
ND	791	105,890	6,753	199,510	7,930	6,727	6
OH	2,268	723,494	24,055	2,935,817	95,761	84,759	20
OK	1,034	100,058	28,434	122,317	12,914	11,875	18
OR	278	14,595	8,921	10,034	1,141	1,053	1
PA	1,953	543,445	22,625	1,281,572	79,086	71,136	16
RI	35	797	1,372	-	111	111	0
SC	771	178,209	11,468	252,385	23,129	18,512	5
SD	109	22,930	521	37,069	217	206	1
TN	918	329,848	7,234	776,098	22,500	20,511	8
TX	5,331	409,714	88,688	649,978	50,546	41,001	292
UT	423	77,371	3,523	36,440	5,594	4,361	4
VT	5	265	214	-	17	17	0
VA	789	164,765	16,795	270,035	18,177	16,057	5
WA	427	34,266	10,903	79,018	3,569	3,023	2
WV	1,509	494,211	14,136	1,262,952	39,373	32,189	13
WI	1,143	169,317	11,796	269,725	16,229	14,803	10
WY	764	108,699	6,376	77,919	9,187	7,613	7
National	**48,001**	**8,686,216**	**750,539**	**18,738,860**	**896,790**	**762,326**	**612**

Table A-14. Electricity Generating Unit with CAAA Scenario – State Emission Summary (tons per year)
Year = 2020

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	1,545	49,053	26,893	194,464	20,599	15,519	10
AZ	1,268	67,069	30,168	50,751	13,357	10,793	6
AR	667	32,035	10,744	22,796	5,295	4,749	7
CA	1,560	23,885	59,135	5,066	5,654	5,552	1
CO	674	61,197	11,850	57,045	4,971	4,385	5
CT	120	3,909	8,864	3,901	819	650	1
DE	118	2,145	1,426	28,271	8,425	4,686	1
DC	12	121	468	0	38	38	0
FL	2,077	58,308	61,101	156,096	26,131	19,968	9
GA	1,958	58,133	34,747	160,247	24,729	17,079	13
ID	34	699	1,315	0	106	106	0
IL	2,352	62,148	17,177	238,336	16,417	13,948	16
IN	2,277	72,472	22,243	304,851	41,385	28,932	18
IA	845	55,215	8,536	164,321	10,432	8,894	7
KS	869	40,501	8,301	58,524	7,668	6,433	7
KY	1,655	62,406	17,834	217,881	27,475	19,540	13
LA	663	32,537	11,639	62,034	4,040	3,657	5
ME	68	1,381	4,696	5,229	300	288	0
MD	639	9,366	16,114	23,383	6,913	4,912	4
MA	451	18,037	12,039	17,391	3,582	2,844	16
MI	1,493	92,817	17,002	285,543	26,572	21,117	12
MN	702	40,965	6,221	85,733	20,003	14,677	6
MS	461	8,608	10,276	21,762	4,260	3,258	3
MO	1,781	71,511	13,809	270,564	29,517	26,427	13
MT	325	38,499	2,991	23,171	7,666	4,861	3
NE	448	42,957	3,654	36,751	3,353	2,914	4
NV	479	30,210	9,620	27,424	5,155	4,225	3
NH	212	3,275	5,173	7,426	1,144	1,043	1
NJ	353	8,341	7,667	31,130	6,641	5,837	2
NM	565	72,014	6,436	52,885	11,578	8,064	8
NY	806	12,826	24,667	47,974	10,189	8,923	3
NC	1,571	53,381	18,579	81,118	31,860	24,534	14
ND	785	39,892	9,948	84,365	7,274	6,135	6
OH	2,268	80,484	24,430	235,874	44,411	31,045	20
OK	1,166	57,472	33,410	44,619	14,828	13,790	23
OR	279	11,182	8,969	10,034	1,145	1,057	1
PA	1,819	62,067	21,000	133,215	32,093	23,551	15
RI	29	397	1,139	0	92	92	0
SC	810	39,531	11,291	108,802	24,207	19,451	6
SD	109	1,778	520	4,185	394	382	1
TN	829	22,342	6,940	98,932	11,711	9,668	7
TX	4,808	149,742	99,005	373,713	37,257	28,429	230
UT	422	53,354	3,519	37,504	5,698	4,469	4
VT	9	86	352	0	28	28	0
VA	792	36,027	16,267	72,394	15,960	13,751	6
WA	429	16,154	10,994	12,236	3,577	3,031	2
WV	1,493	40,153	14,255	105,836	25,198	17,367	13
WI	1,141	34,978	11,945	155,793	18,109	16,676	10
WY	754	53,093	6,288	50,554	9,057	7,483	7
National	**46,992**	**1,884,754**	**771,654**	**4,270,125**	**637,311**	**495,254**	**559**

Table A-15. Nonroad Model Sector – State Emission Summary (tons per year)
Year = 1990

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	43,942	27,729	325,257	2,087	3,921	3,609	21
AZ	40,492	18,897	368,150	1,573	2,862	2,634	19
AR	26,692	29,078	188,514	2,274	4,519	4,158	18
CA	270,139	164,566	2,615,018	13,095	22,927	21,101	142
CO	32,472	25,997	293,021	2,133	3,866	3,557	20
CT	33,136	18,369	293,745	1,357	2,439	2,245	16
DE	9,590	5,490	67,735	428	831	765	5
DC	1,453	2,272	13,867	197	277	255	1
FL	189,032	79,645	1,432,534	6,873	13,202	12,148	81
GA	66,405	48,508	597,276	3,777	6,464	5,950	37
ID	16,198	13,446	103,274	1,098	2,276	2,094	9
IL	105,715	99,525	970,221	7,652	14,470	13,316	68
IN	55,247	58,967	525,107	4,466	8,184	7,533	38
IA	40,488	74,354	317,009	5,936	12,679	11,666	40
KS	29,687	62,733	269,102	5,026	10,507	9,667	33
KY	31,957	27,658	255,287	2,111	4,054	3,731	19
LA	45,350	30,464	314,835	2,507	4,785	4,404	24
ME	25,253	9,528	139,797	785	1,632	1,502	10
MD	45,110	22,178	386,622	1,826	3,426	3,153	21
MA	59,215	55,981	522,907	4,614	7,180	6,608	40
MI	138,888	63,132	940,478	4,718	9,828	9,045	60
MN	95,892	73,946	547,420	5,884	13,035	11,994	53
MS	28,680	24,108	186,720	1,872	3,640	3,350	16
MO	56,788	55,994	464,923	4,355	9,045	8,323	37
MT	10,078	18,887	69,777	1,562	3,241	2,982	10
NE	21,476	49,299	181,808	3,958	8,514	7,834	25
NV	14,488	10,293	124,664	918	1,496	1,376	8
NH	18,544	7,094	121,552	541	1,121	1,032	7
NJ	81,044	47,409	724,758	3,611	6,516	5,997	40
NM	9,757	7,142	86,030	601	1,070	985	6
NY	146,124	101,942	1,248,144	8,076	14,112	12,988	81
NC	72,873	55,652	631,196	4,128	7,154	6,585	40
ND	16,782	52,561	111,031	4,280	9,445	8,689	25
OH	110,390	84,683	1,011,598	6,421	11,529	10,611	63
OK	29,920	31,457	253,644	2,530	5,028	4,626	21
OR	37,047	32,306	303,335	2,640	4,558	4,194	23
PA	100,227	71,591	949,399	5,257	9,232	8,498	55
RI	7,900	4,181	74,840	290	525	484	4
SC	40,269	25,163	313,984	1,901	3,434	3,161	20
SD	14,179	38,307	97,016	3,098	6,826	6,280	19
TN	49,642	37,282	402,556	2,799	5,105	4,698	27
TX	155,162	129,097	1,492,385	10,355	18,596	17,114	95
UT	19,112	18,530	138,862	1,584	2,524	2,322	13
VT	9,121	4,029	58,575	316	654	602	4
VA	57,593	38,727	504,227	3,092	5,426	4,994	31
WA	57,729	45,963	469,079	3,728	6,621	6,092	34
WV	12,395	9,457	98,619	757	1,351	1,243	7
WI	79,627	48,340	528,848	3,678	7,475	6,879	39
WY	6,409	5,784	41,516	489	960	884	4
National	**2,665,710**	**2,067,745**	**22,176,262**	**163,254**	**308,562**	**283,960**	**1,530**

Table A-16. Nonroad Model Sector without CAAA Scenario – State Emission Summary (tons per year)
Year = 2000

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	53,820	31,262	372,810	2,448	4,026	3,706	26
AZ	59,027	29,411	529,872	2,548	3,863	3,555	29
AR	33,704	32,157	222,627	2,618	4,231	3,894	22
CA	326,970	175,652	3,063,853	13,990	22,153	20,392	165
CO	46,389	36,508	414,449	3,126	4,449	4,094	30
CT	37,773	19,561	313,432	1,469	2,416	2,224	18
DE	12,147	6,229	81,606	501	890	819	6
DC	1,770	2,510	16,494	223	263	242	2
FL	247,749	91,075	1,773,150	8,034	14,517	13,359	102
GA	84,206	54,575	721,098	4,364	6,544	6,024	45
ID	23,253	15,914	143,181	1,363	2,283	2,101	13
IL	120,255	107,240	1,057,828	8,543	13,127	12,082	79
IN	62,031	63,579	564,436	4,987	7,383	6,796	44
IA	43,362	66,451	331,671	5,473	9,452	8,697	41
KS	31,014	56,532	282,673	4,672	7,796	7,174	34
KY	38,863	30,462	289,083	2,428	3,899	3,589	23
LA	59,188	35,860	378,614	3,035	4,963	4,567	30
ME	29,219	9,113	151,874	779	1,513	1,393	11
MD	57,826	25,348	476,411	2,138	3,660	3,368	26
MA	66,943	58,913	557,415	4,964	6,679	6,148	45
MI	163,257	68,336	1,025,870	5,264	9,820	9,039	68
MN	110,711	69,744	597,896	5,743	10,858	9,992	58
MS	35,513	26,214	212,054	2,118	3,464	3,188	19
MO	65,814	54,589	506,622	4,368	7,593	6,988	40
MT	13,405	20,809	91,645	1,818	2,866	2,637	13
NE	22,183	43,112	188,064	3,574	6,189	5,694	25
NV	21,630	16,878	184,006	1,560	2,065	1,900	14
NH	21,517	7,412	130,882	578	1,136	1,046	8
NJ	90,952	44,342	764,610	3,442	5,867	5,401	42
NM	14,327	10,371	123,135	909	1,303	1,199	9
NY	164,324	95,294	1,317,944	7,720	12,352	11,369	85
NC	91,665	62,389	747,981	4,758	7,240	6,666	49
ND	15,930	44,143	107,183	3,726	6,628	6,098	24
OH	126,565	92,472	1,096,259	7,220	10,970	10,098	72
OK	37,646	34,310	299,698	2,858	4,599	4,232	25
OR	45,574	32,126	353,188	2,687	4,032	3,711	26
PA	110,240	67,201	983,603	5,082	8,001	7,366	57
RI	8,949	4,476	79,614	314	527	485	4
SC	51,124	28,120	374,881	2,184	3,553	3,271	24
SD	14,070	32,441	95,892	2,714	4,840	4,453	18
TN	60,391	42,613	455,965	3,324	5,164	4,753	33
TX	196,136	151,825	1,806,737	12,571	18,494	17,021	121
UT	28,893	29,753	201,572	2,660	3,398	3,127	22
VT	10,394	4,175	63,034	336	622	573	4
VA	72,691	43,337	611,010	3,566	5,520	5,081	38
WA	71,028	46,827	548,835	3,885	6,042	5,560	39
WV	16,084	10,201	117,908	854	1,337	1,230	9
WI	92,027	51,525	573,617	4,058	7,029	6,470	45
WY	9,260	7,323	56,647	653	1,007	927	6
National	**3,217,810**	**2,190,711**	**25,458,930**	**178,247**	**286,623**	**263,798**	**1,789**

Table A-17. Nonroad Model Sector with CAAA Scenario – State Emission Summary (tons per year)
Year = 2000

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	44,858	29,251	342,388	2,440	3,703	3,409	25
AZ	42,890	28,754	399,760	2,532	3,502	3,223	28
AR	28,789	30,154	205,584	2,615	3,960	3,644	22
CA	237,704	173,505	2,545,659	13,849	20,306	18,692	155
CO	34,860	35,055	331,499	3,116	4,066	3,742	28
CT	29,108	19,203	269,131	1,461	2,221	2,045	17
DE	9,883	6,030	70,298	499	828	762	5
DC	1,325	2,312	14,030	223	235	216	2
FL	199,860	87,328	1,615,215	7,984	13,469	12,394	97
GA	65,496	51,708	652,492	4,344	5,977	5,502	43
ID	20,104	14,900	132,021	1,361	2,139	1,968	13
IL	92,821	103,083	903,590	8,518	12,203	11,232	76
IN	48,335	60,519	495,224	4,975	6,831	6,289	42
IA	36,118	63,331	305,719	5,468	9,032	8,311	40
KS	24,643	53,788	258,535	4,667	7,427	6,834	33
KY	31,866	28,654	257,911	2,400	3,598	3,312	22
LA	50,612	33,630	348,656	3,029	4,618	4,250	29
ME	26,383	8,520	141,934	777	1,417	1,304	11
MD	43,517	24,451	405,801	2,086	3,302	3,039	25
MA	51,540	55,541	472,964	4,952	6,059	5,577	43
MI	141,156	66,015	927,039	5,242	9,195	8,464	66
MN	99,685	66,560	560,423	5,735	10,360	9,533	57
MS	30,441	24,366	195,891	2,115	3,218	2,962	19
MO	53,244	52,750	435,492	4,357	7,172	6,601	39
MT	11,540	19,530	83,398	1,818	2,711	2,494	13
NE	18,086	41,142	172,714	3,571	5,930	5,457	25
NV	15,932	15,855	136,245	1,555	1,853	1,705	13
NH	18,543	7,234	116,450	575	1,064	979	8
NJ	70,056	44,142	656,694	3,420	5,469	5,035	40
NM	11,145	9,834	103,800	906	1,190	1,095	8
NY	131,373	91,741	1,152,540	7,601	11,400	10,493	81
NC	72,886	59,010	682,700	4,740	6,618	6,094	47
ND	13,960	42,079	99,721	3,726	6,396	5,884	24
OH	99,443	87,927	1,001,470	7,193	10,096	9,294	69
OK	31,125	32,566	274,135	2,852	4,319	3,975	24
OR	35,988	30,556	293,772	2,679	3,711	3,416	25
PA	86,852	65,502	882,345	5,056	7,440	6,850	54
RI	6,822	4,452	68,483	312	484	446	4
SC	41,629	26,561	342,397	2,176	3,262	3,003	23
SD	12,253	30,939	89,217	2,714	4,665	4,292	18
TN	49,234	40,195	418,325	3,314	4,753	4,376	32
TX	150,235	144,201	1,588,807	12,525	17,010	15,655	116
UT	23,972	27,091	180,271	2,657	3,051	2,808	21
VT	9,163	4,008	58,693	335	585	538	4
VA	50,377	37,351	469,485	3,203	4,577	4,213	33
WA	56,903	44,330	494,831	3,872	5,586	5,141	38
WV	13,529	9,657	108,350	851	1,242	1,143	8
WI	80,314	49,305	515,681	4,048	6,588	6,064	43
WY	8,192	6,841	52,330	653	942	866	6
National	**2,564,790**	**2,091,459**	**22,330,110**	**177,095**	**265,778**	**244,620**	**1,715**

Table A-18. Nonroad Model Sector without CAAA Scenario – State Emission Summary (tons per year)
Year = 2010

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	67,591	35,516	450,053	2,838	4,535	4,174	31
AZ	81,516	41,374	706,406	3,658	5,251	4,833	41
AR	47,696	36,495	288,481	3,086	4,473	4,117	27
CA	430,704	240,385	3,948,811	19,720	28,682	26,402	222
CO	66,051	50,650	563,214	4,491	5,760	5,301	42
CT	44,371	23,975	370,520	1,845	2,831	2,607	21
DE	15,142	7,935	102,400	655	1,057	973	7
DC	2,199	3,204	20,853	291	322	296	2
FL	297,870	117,240	2,279,309	10,586	17,732	16,318	131
GA	113,005	69,847	934,867	5,715	8,138	7,492	59
ID	34,922	21,443	200,264	1,932	2,834	2,608	19
IL	143,790	129,943	1,244,207	10,854	14,158	13,032	97
IN	76,023	76,397	663,007	6,277	8,020	7,383	54
IA	51,408	71,904	387,699	6,342	8,434	7,761	48
KS	36,214	61,504	329,608	5,437	6,956	6,401	40
KY	49,594	34,810	347,801	2,877	4,217	3,882	27
LA	75,818	40,294	460,599	3,536	5,556	5,113	36
ME	38,410	10,426	188,544	914	1,805	1,661	14
MD	73,674	32,647	610,026	2,822	4,487	4,129	34
MA	78,694	71,895	656,809	6,211	7,812	7,190	54
MI	204,310	81,319	1,221,654	6,479	11,315	10,416	83
MN	140,549	78,755	725,033	6,863	10,908	10,039	70
MS	44,749	29,376	256,504	2,455	3,696	3,402	23
MO	79,387	63,115	603,273	5,289	7,682	7,070	48
MT	20,069	27,865	127,544	2,605	3,245	2,986	19
NE	25,976	45,851	218,075	4,094	5,357	4,929	29
NV	29,651	23,792	237,932	2,231	2,804	2,580	20
NH	27,029	8,987	158,318	718	1,366	1,258	10
NJ	105,833	53,757	895,220	4,328	6,750	6,213	51
NM	20,586	14,396	166,937	1,299	1,726	1,589	12
NY	197,431	115,387	1,564,986	9,722	14,233	13,101	104
NC	121,305	79,466	961,147	6,202	8,893	8,187	63
ND	18,095	45,265	120,743	4,174	5,435	5,001	28
OH	151,760	109,593	1,279,396	8,836	12,186	11,219	87
OK	48,044	38,674	374,839	3,366	4,639	4,269	30
OR	61,988	41,778	459,376	3,593	5,018	4,618	35
PA	137,040	80,596	1,164,773	6,385	9,356	8,614	70
RI	10,450	5,510	93,909	396	618	570	5
SC	65,168	35,659	476,413	2,826	4,332	3,989	31
SD	16,337	33,560	109,567	3,053	4,035	3,712	21
TN	75,071	49,206	544,744	3,935	5,750	5,293	39
TX	250,263	177,683	2,251,419	15,125	20,312	18,696	148
UT	43,170	41,535	277,148	3,804	4,668	4,295	31
VT	13,792	4,913	78,339	412	726	668	6
VA	94,471	55,195	783,097	4,659	6,742	6,205	49
WA	93,913	61,138	710,450	5,231	7,412	6,822	52
WV	25,335	12,826	160,852	1,110	1,770	1,629	12
WI	116,210	61,770	686,423	5,090	7,876	7,249	56
WY	14,123	9,985	80,227	933	1,276	1,174	8
National	**4,076,796**	**2,664,838**	**31,541,817**	**225,300**	**323,187**	**297,466**	**2,248**

Table A-19. Nonroad Model Sector with CAAA Scenario – State Emission Summary (tons per year)
Year = 2010[1]

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	32,807	20,509	388,103	220	2,809	2,587	28
AZ	31,954	24,586	514,640	274	3,148	2,898	36
AR	25,430	22,475	248,027	233	2,833	2,608	26
CA	158,493	143,166	3,141,091	1,483	17,636	16,240	195
CO	28,879	30,588	428,135	332	3,465	3,189	38
CT	17,880	14,005	302,171	143	1,732	1,596	19
DE	6,309	4,885	82,948	51	651	599	6
DC	832	1,771	16,639	21	171	158	2
FL	134,625	74,798	1,992,404	817	11,019	10,141	115
GA	48,704	39,905	811,550	432	4,905	4,517	53
ID	20,097	13,575	172,783	144	1,849	1,702	17
IL	62,715	79,666	1,002,083	810	8,893	8,188	90
IN	33,674	45,745	543,453	468	4,966	4,573	50
IA	26,376	49,281	330,912	467	5,786	5,325	46
KS	16,235	41,722	281,425	399	4,705	4,330	38
KY	24,185	20,960	292,235	216	2,607	2,400	25
LA	39,503	24,869	404,247	272	3,421	3,149	33
ME	23,941	6,336	163,387	71	1,238	1,140	13
MD	28,902	19,937	500,653	211	2,738	2,520	29
MA	32,063	41,948	524,188	465	4,477	4,122	50
MI	114,372	48,940	1,030,576	504	7,461	6,870	76
MN	85,753	52,490	623,017	519	7,531	6,931	67
MS	24,105	17,730	220,648	187	2,325	2,141	21
MO	37,299	40,943	489,487	399	5,019	4,620	45
MT	11,442	18,646	107,327	191	2,102	1,934	19
NE	12,632	32,101	187,030	300	3,712	3,416	28
NV	12,051	13,854	174,750	164	1,581	1,455	18
NH	14,950	5,524	132,162	57	900	829	9
NJ	42,841	34,353	740,674	333	4,238	3,903	45
NM	9,284	8,642	135,740	96	1,021	939	11
NY	91,527	71,673	1,308,401	730	8,784	8,088	93
NC	52,802	44,767	823,765	474	5,355	4,933	57
ND	10,493	33,118	100,358	304	3,880	3,570	27
OH	66,464	63,670	1,109,590	668	7,478	6,887	79
OK	22,915	24,701	327,232	252	2,938	2,705	28
OR	28,212	25,231	361,407	269	3,087	2,842	32
PA	63,284	49,395	999,258	484	5,877	5,413	63
RI	4,071	3,230	76,926	31	380	350	4
SC	29,807	20,437	411,628	218	2,643	2,434	27
SD	9,356	24,256	92,135	223	2,866	2,637	20
TN	35,885	28,517	470,976	300	3,502	3,225	36
TX	103,572	106,248	1,906,469	1,133	12,305	11,330	134
UT	22,666	23,218	231,181	281	2,618	2,409	29
VT	8,268	3,041	67,696	32	490	451	5
VA	34,856	29,499	573,021	318	3,694	3,401	39
WA	42,343	37,031	606,385	394	4,587	4,222	47
WV	13,929	7,753	141,754	84	1,098	1,011	11
WI	67,243	38,003	568,880	388	5,178	4,768	52
WY	8,699	6,288	69,536	69	807	743	8
National	**1,874,723**	**1,634,024**	**26,229,083**	**16,930**	**202,507**	**186,440**	**2,042**

[1] PM2.5 emission totals do not reflect reductions from local controls implemented for compliance with the PM2.5 NAAQS. PM2.5 emission reductions from such local controls are reflected in the by-state totals for nonpoint sources. Emission totals in Chapter 1 do reflect PM2.5 NAAQS local controls for the nonroad sector and therefore do not match the totals presented here.

Table A-20. Nonroad Model Sector without CAAA Scenario – State Emission Summary (tons per year)
Year = 2020

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	74,529	39,048	504,654	3,143	4,886	4,498	34
AZ	101,885	56,527	892,036	5,001	6,843	6,298	53
AR	56,418	41,223	345,036	3,480	4,830	4,446	31
CA	525,023	316,456	4,867,725	26,048	36,065	33,200	282
CO	83,817	67,789	715,422	6,041	7,368	6,781	55
CT	49,846	28,353	423,710	2,204	3,239	2,982	25
DE	17,659	9,685	122,597	806	1,237	1,139	9
DC	2,615	3,925	25,193	358	389	358	3
FL	351,068	144,533	2,765,402	13,118	20,991	19,317	159
GA	135,631	85,419	1,137,270	7,031	9,701	8,930	72
ID	44,363	27,416	254,234	2,491	3,434	3,161	24
IL	161,951	155,202	1,408,969	13,247	15,998	14,726	116
IN	85,396	90,891	745,703	7,632	9,079	8,358	64
IA	57,182	77,083	433,523	6,963	8,196	7,543	53
KS	39,902	66,175	368,295	5,988	6,771	6,231	44
KY	54,907	38,401	389,824	3,211	4,485	4,129	30
LA	88,140	44,606	534,965	3,939	6,121	5,633	41
ME	45,165	11,674	218,838	1,031	2,041	1,878	16
MD	87,782	40,173	740,984	3,495	5,336	4,911	42
MA	88,756	85,224	749,643	7,421	9,056	8,335	64
MI	231,367	95,152	1,375,845	7,728	12,766	11,752	97
MN	161,469	86,658	824,919	7,710	11,358	10,453	80
MS	49,133	31,818	285,714	2,687	3,871	3,563	25
MO	87,833	70,412	679,470	5,999	7,992	7,357	54
MT	25,324	34,979	160,830	3,328	3,780	3,478	25
NE	28,485	48,606	242,648	4,455	5,091	4,685	32
NV	37,069	32,580	300,357	3,067	3,708	3,412	26
NH	31,095	10,519	181,961	848	1,560	1,436	12
NJ	117,096	60,557	1,012,284	4,919	7,401	6,813	57
NM	25,778	19,323	211,156	1,752	2,215	2,039	16
NY	221,359	129,735	1,776,136	11,029	15,629	14,387	118
NC	144,418	96,835	1,160,278	7,603	10,543	9,707	76
ND	19,718	46,830	132,073	4,465	4,970	4,573	30
OH	168,672	128,784	1,431,898	10,572	13,764	12,671	101
OK	56,417	43,311	446,254	3,791	4,949	4,555	35
OR	75,696	53,525	566,453	4,618	6,196	5,703	43
PA	154,059	90,606	1,313,052	7,259	10,330	9,510	79
RI	11,754	6,522	107,498	474	708	652	6
SC	76,934	43,285	573,176	3,449	5,107	4,702	37
SD	17,908	34,905	120,575	3,275	3,729	3,431	23
TN	83,059	54,834	611,051	4,431	6,226	5,732	44
TX	297,143	202,831	2,701,524	17,238	22,536	20,744	172
UT	54,815	56,837	351,975	5,225	6,194	5,700	41
VT	16,211	5,609	90,885	474	817	752	6
VA	112,661	67,406	948,656	5,726	8,009	7,372	60
WA	114,385	78,645	875,800	6,753	9,130	8,403	65
WV	30,594	15,469	194,195	1,348	2,108	1,940	14
WI	132,897	73,036	776,919	6,151	8,907	8,199	65
WY	18,113	12,998	101,871	1,229	1,591	1,464	11
National	**4,753,500**	**3,162,409**	**37,199,473**	**270,252**	**367,252**	**338,036**	**2,665**

Table A-21. Nonroad Model Sector with CAAA Scenario – State Emission Summary (tons per year)
Year = 2020[2]

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	24,163	11,539	409,478	39	1,794	1,653	30
AZ	29,291	16,182	620,236	52	2,319	2,136	47
AR	18,132	12,815	273,234	33	1,632	1,504	29
CA	142,339	97,155	3,696,579	296	13,176	12,142	247
CO	25,029	19,473	509,296	51	2,251	2,074	50
CT	14,989	8,623	327,398	28	1,234	1,138	22
DE	5,339	3,259	93,756	10	491	452	8
DC	732	952	18,756	2	89	82	3
FL	124,773	51,199	2,343,203	169	8,752	8,057	139
GA	40,793	23,793	939,111	77	3,290	3,032	65
ID	15,121	8,976	197,443	23	1,213	1,116	22
IL	48,870	49,025	1,053,079	115	5,464	5,034	106
IN	25,411	26,848	563,271	64	2,931	2,702	59
IA	18,772	28,624	334,940	48	3,057	2,814	50
KS	12,262	23,834	291,782	39	2,436	2,243	42
KY	17,014	11,896	305,883	32	1,521	1,401	28
LA	31,093	14,836	444,196	45	2,261	2,082	37
ME	16,013	4,112	164,033	18	856	788	14
MD	26,722	13,551	588,330	43	2,114	1,947	36
MA	25,949	22,579	558,241	62	2,681	2,470	59
MI	78,794	31,680	1,038,036	111	5,042	4,646	86
MN	56,892	32,335	607,800	83	4,507	4,150	73
MS	17,153	9,769	227,392	27	1,363	1,256	23
MO	28,059	24,396	515,853	57	2,963	2,730	50
MT	8,301	12,052	120,863	20	1,229	1,131	24
NE	9,082	18,685	191,786	28	1,913	1,761	31
NV	10,832	8,260	209,419	22	1,015	934	24
NH	10,576	3,674	136,758	14	644	593	10
NJ	35,560	21,215	799,936	64	3,005	2,769	50
NM	7,925	5,498	163,087	15	664	612	15
NY	69,568	42,868	1,390,632	125	5,724	5,274	104
NC	43,948	26,170	934,351	86	3,612	3,331	69
ND	6,742	19,502	94,406	24	1,941	1,786	29
OH	51,909	37,085	1,166,363	107	4,700	4,332	91
OK	18,684	14,683	370,349	35	1,783	1,642	32
OR	23,212	15,799	416,291	44	2,126	1,959	40
PA	47,754	28,237	1,058,002	86	3,754	3,460	70
RI	3,474	2,011	83,452	7	278	256	5
SC	25,851	12,385	467,921	42	1,901	1,752	33
SD	6,127	14,282	88,563	19	1,454	1,338	22
TN	26,360	15,584	495,066	49	2,094	1,930	40
TX	90,205	61,096	2,191,703	177	7,779	7,167	154
UT	17,273	13,021	264,333	36	1,501	1,382	39
VT	5,531	1,920	69,167	7	319	294	6
VA	30,607	18,206	662,632	56	2,600	2,395	48
WA	35,442	23,692	701,359	67	3,240	2,985	59
WV	9,590	4,784	161,275	15	669	616	13
WI	45,054	23,968	561,878	71	3,301	3,041	59
WY	6,331	4,127	78,538	10	504	464	10
National	**1,489,644**	**996,255**	**28,999,459**	**2,750**	**131,185**	**120,854**	**2,399**

[2] $PM_{2.5}$ emission totals do not reflect reductions from local controls implemented for compliance with the $PM_{2.5}$ NAAQS. $PM_{2.5}$ emission reductions from such local controls are reflected in the by-state totals for nonpoint sources. Emission totals in Chapter 1 do reflect $PM_{2.5}$ NAAQS local controls for the nonroad sector and therefore do not match the totals presented here.

Table A-22. Onroad – State Emissions Summary (tons per year)
Year = 1990

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	206,699	202,489	2,340,754	11,096	8,631	7,271	3,186
AZ	151,393	162,024	1,616,752	9,213	7,155	6,022	2,672
AR	97,149	102,936	1,160,472	5,801	4,553	3,854	1,578
CA	1,064,709	1,054,362	11,893,765	53,550	40,408	33,382	18,458
CO	133,878	121,169	1,785,066	6,746	5,203	4,360	2,049
CT	105,516	119,584	1,244,747	5,894	4,465	3,698	1,988
DE	28,214	33,501	330,164	1,845	1,438	1,212	527
DC	13,089	13,209	141,600	598	437	354	238
FL	520,817	434,428	5,354,388	22,616	17,177	14,262	7,452
GA	300,864	299,260	3,431,841	16,160	12,490	10,478	4,842
ID	45,534	50,808	569,546	2,789	2,196	1,864	738
IL	367,640	391,956	4,363,438	19,539	14,911	12,415	6,288
IN	215,109	235,391	2,635,044	12,586	9,810	8,273	3,574
IA	108,333	117,732	1,367,697	6,369	4,998	4,233	1,727
KS	103,922	112,697	1,288,874	6,038	4,705	3,967	1,719
KY	146,729	165,155	1,759,072	9,073	7,093	5,992	2,528
LA	132,804	130,927	1,483,152	7,344	5,729	4,834	2,073
ME	52,799	62,624	691,968	3,432	2,711	2,304	890
MD	174,202	186,031	2,107,171	9,568	7,318	6,099	3,059
MA	183,175	187,371	2,206,343	9,036	6,786	5,591	3,183
MI	367,771	386,236	4,611,340	19,652	15,133	12,666	6,026
MN	187,158	194,611	2,384,244	9,932	7,696	6,466	2,933
MS	119,647	120,034	1,352,650	6,887	5,420	4,597	1,830
MO	205,492	224,464	2,532,466	11,946	9,257	7,775	3,542
MT	37,906	44,112	495,698	2,436	1,928	1,640	624
NE	64,758	71,176	814,354	3,837	3,007	2,545	1,048
NV	48,944	45,302	589,060	2,530	1,950	1,634	769
NH	43,604	50,422	569,196	2,700	2,116	1,791	739
NJ	248,800	249,902	2,622,595	12,262	9,162	7,526	4,416
NM	84,002	75,287	1,107,097	4,377	3,423	2,893	1,213
NY	469,026	488,427	5,469,579	24,578	18,700	15,535	8,076
NC	280,106	268,891	3,192,565	13,827	10,572	8,812	4,410
ND	28,910	31,583	374,548	1,709	1,349	1,147	443
OH	388,889	387,688	4,671,949	19,763	15,183	12,690	6,142
OK	149,618	157,614	1,782,079	8,527	6,617	5,565	2,495
OR	113,067	130,902	1,406,346	7,052	5,494	4,632	2,011
PA	369,766	400,873	4,379,790	20,948	16,189	13,583	6,269
RI	31,900	32,369	353,404	1,537	1,146	941	558
SC	163,397	168,069	1,910,134	9,532	7,484	6,338	2,581
SD	32,428	37,098	422,785	2,062	1,634	1,391	523
TN	220,639	222,372	2,568,092	11,965	9,274	7,795	3,516
TX	691,779	669,792	7,966,039	34,938	26,670	22,199	11,284
UT	76,262	65,031	1,012,734	3,553	2,729	2,281	1,105
VT	26,626	31,020	352,112	1,682	1,328	1,129	438
VA	267,173	284,513	3,150,900	15,226	11,782	9,891	4,532
WA	198,215	212,275	2,418,358	10,763	8,258	6,896	3,374
WV	67,569	77,926	833,951	4,404	3,475	2,951	1,156
WI	165,077	193,135	2,094,589	10,435	8,186	6,930	2,843
WY	26,559	31,218	356,490	1,709	1,353	1,151	436
National	**9,327,660**	**9,535,993**	**109,566,997**	**500,064**	**384,733**	**321,852**	**154,103**

Table A-23. Onroad without CAAA Scenario – State Emissions Summary (tons per year)
Year = 2000

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	128,854	169,270	1,505,878	12,354	4,823	3,738	5,338
AZ	107,137	179,898	1,200,917	13,828	5,369	4,266	4,990
AR	63,414	104,696	852,352	7,928	3,073	2,440	2,886
CA	604,738	704,422	7,623,547	47,088	18,740	13,582	29,477
CO	90,145	132,619	1,363,869	9,356	3,667	2,822	4,247
CT	60,931	98,417	917,021	6,851	2,674	2,057	3,102
DE	16,926	26,640	231,208	1,986	774	604	825
DC	7,566	9,988	94,032	667	264	197	356
FL	381,392	470,905	3,877,651	33,874	13,266	10,217	15,344
GA	229,852	350,232	2,942,087	26,045	10,136	7,942	10,488
ID	28,224	49,189	417,811	3,660	1,421	1,128	1,340
IL	217,647	340,428	3,190,740	23,600	9,222	7,138	10,348
IN	152,412	247,002	2,177,380	18,063	7,026	5,529	7,058
IA	66,761	107,988	996,849	7,985	3,098	2,460	2,913
KS	58,749	98,200	831,665	7,243	2,814	2,217	2,799
KY	95,071	165,166	1,341,692	12,307	4,778	3,777	4,647
LA	90,197	140,782	1,106,534	10,593	4,115	3,246	4,062
ME	27,740	41,681	446,871	2,786	1,114	845	1,396
MD	100,484	162,019	1,450,413	11,619	4,528	3,508	5,043
MA	108,085	165,752	1,557,672	11,407	4,488	3,439	5,281
MI	216,556	329,963	3,207,627	23,411	9,125	7,111	9,800
MN	119,092	185,594	1,859,027	13,247	5,149	4,044	5,246
MS	77,218	133,324	926,817	10,515	4,090	3,301	3,498
MO	141,073	229,874	2,022,437	16,780	6,523	5,116	6,694
MT	20,362	38,169	331,854	2,841	1,100	880	972
NE	38,659	65,949	576,465	4,866	1,889	1,498	1,791
NV	36,972	57,694	539,037	4,109	1,605	1,245	1,772
NH	24,526	43,449	393,745	3,187	1,237	979	1,193
NJ	136,852	206,035	1,880,996	14,608	5,719	4,381	6,818
NM	51,002	81,998	729,149	6,174	2,396	1,903	2,253
NY	271,169	411,656	3,749,564	29,291	11,444	8,839	12,995
NC	203,151	302,089	2,579,583	22,653	8,812	6,927	8,922
ND	16,270	27,822	263,238	2,054	795	636	711
OH	238,000	357,112	3,419,797	25,509	9,935	7,748	10,606
OK	91,941	148,788	1,216,265	11,125	4,326	3,400	4,380
OR	73,085	120,890	1,089,444	8,912	3,463	2,725	3,414
PA	215,654	348,134	3,034,209	25,319	9,857	7,721	10,223
RI	17,241	25,707	248,532	1,739	682	519	848
SC	102,059	163,918	1,339,764	12,347	4,788	3,801	4,507
SD	18,030	32,782	292,485	2,430	940	753	829
TN	146,899	224,124	1,944,417	16,327	6,358	4,987	6,548
TX	475,185	703,440	5,854,596	51,377	20,035	15,546	22,103
UT	50,065	74,046	734,341	5,147	2,009	1,554	2,260
VT	14,362	25,745	229,987	1,912	741	591	672
VA	155,443	210,399	2,164,320	13,967	5,532	4,108	7,801
WA	112,988	174,224	1,629,804	12,360	4,819	3,735	5,360
WV	36,502	60,151	532,135	4,151	1,629	1,254	1,925
WI	119,809	202,507	1,851,981	14,883	5,783	4,564	5,693
WY	16,493	31,234	269,278	2,281	884	706	797
National	**5,872,983**	**8,782,108**	**79,037,081**	**632,766**	**247,056**	**191,723**	**272,569**

Table A-24. Onroad with CAAA Scenario – State Emissions Summary (tons per year)
Year = 2000

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	114,123	158,673	1,369,792	5,719	4,364	3,279	5,338
AZ	94,470	167,877	1,061,081	5,641	4,807	3,704	4,990
AR	59,164	97,742	765,290	3,173	2,743	2,110	2,886
CA	450,793	605,783	5,442,803	14,553	16,528	11,362	29,372
CO	84,020	123,828	1,192,589	4,523	3,334	2,489	4,247
CT	48,231	87,514	706,379	2,006	2,342	1,725	3,102
DE	13,569	24,215	175,681	521	673	503	825
DC	6,281	8,846	72,695	204	231	165	356
FL	349,666	442,574	3,668,439	16,325	12,053	9,004	15,344
GA	207,136	324,829	2,596,468	11,625	9,137	6,944	10,488
ID	26,842	45,626	370,927	1,467	1,269	976	1,340
IL	195,319	307,196	2,533,311	8,463	8,170	6,086	10,348
IN	143,248	228,277	1,874,680	7,341	6,283	4,786	7,058
IA	60,569	99,871	843,185	3,157	2,763	2,125	2,913
KS	57,526	91,849	772,685	3,195	2,533	1,937	2,799
KY	87,788	152,894	1,163,065	4,652	4,248	3,246	4,647
LA	85,239	131,911	1,028,779	4,436	3,688	2,819	4,062
ME	25,801	38,354	405,139	1,394	1,018	749	1,396
MD	81,906	146,756	1,126,155	3,391	3,963	2,943	5,043
MA	90,383	151,252	1,256,434	3,454	3,940	2,890	5,281
MI	204,955	307,765	2,813,626	10,729	8,248	6,233	9,800
MN	110,754	172,012	1,607,489	5,518	4,614	3,508	5,246
MS	70,390	124,556	809,681	3,784	3,623	2,835	3,498
MO	130,923	212,108	1,690,296	6,446	5,808	4,402	6,694
MT	19,677	35,281	292,409	1,100	979	760	972
NE	37,405	61,110	515,564	2,012	1,691	1,300	1,791
NV	38,817	52,484	446,206	1,851	1,448	1,089	1,772
NH	22,402	40,379	340,205	1,128	1,095	837	1,193
NJ	125,832	192,800	1,636,080	4,117	4,994	3,657	6,818
NM	49,604	76,121	658,329	2,485	2,140	1,647	2,253
NY	233,586	377,284	3,275,510	11,077	10,181	7,577	12,995
NC	180,258	280,644	2,220,806	9,981	7,934	6,049	8,922
ND	14,970	25,669	225,326	786	707	548	711
OH	209,588	325,562	2,855,921	11,153	8,941	6,754	10,606
OK	92,325	139,220	1,137,568	4,816	3,889	2,963	4,380
OR	66,130	111,321	915,570	3,784	3,109	2,371	3,414
PA	192,193	322,243	2,688,303	9,877	8,787	6,651	10,223
RI	14,663	23,415	199,789	533	599	435	848
SC	95,561	153,176	1,210,637	5,211	4,293	3,307	4,507
SD	16,795	30,244	248,691	922	835	648	829
TN	132,759	208,153	1,682,967	7,187	5,725	4,354	6,548
TX	445,843	651,699	4,936,993	20,137	17,873	13,384	22,103
UT	45,549	68,322	615,044	2,432	1,821	1,366	2,260
VT	13,342	23,683	215,281	738	659	509	672
VA	143,946	192,975	1,899,714	6,806	5,038	3,614	7,801
WA	97,929	160,123	1,349,110	5,484	4,344	3,259	5,360
WV	34,630	55,782	479,190	1,864	1,470	1,095	1,925
WI	106,361	184,635	1,491,603	5,471	5,131	3,911	5,693
WY	16,496	29,107	247,380	921	789	611	797
National	**5,245,756**	**8,073,738**	**67,130,866**	**253,592**	**220,854**	**165,515**	**272,464**

Table A-25. Onroad without CAAA Scenario – State Emissions Summary (tons per year)
Year = 2010

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	120,819	168,910	1,429,004	14,801	4,043	2,952	6,217
AZ	122,342	208,515	1,384,280	19,715	5,200	3,895	7,032
AR	62,394	108,008	870,335	10,060	2,667	1,999	3,593
CA	632,106	773,666	8,255,502	61,415	29,393	22,772	37,730
CO	88,018	141,845	1,403,649	12,201	3,355	2,424	5,424
CT	57,592	96,478	934,807	8,151	2,245	1,625	3,605
DE	17,171	28,777	248,344	2,579	700	515	1,042
DC	6,925	9,639	87,938	755	217	153	394
FL	412,015	534,975	4,155,758	46,068	12,767	9,258	20,385
GA	235,136	378,101	3,106,762	34,328	9,272	6,849	13,523
ID	28,232	52,874	447,293	4,828	1,285	963	1,741
IL	198,735	330,843	3,118,556	27,758	7,632	5,562	11,896
IN	139,977	246,860	2,127,024	22,020	5,918	4,394	8,409
IA	59,050	102,406	943,905	9,249	2,459	1,842	3,330
KS	53,321	95,961	792,240	8,610	2,311	1,715	3,285
KY	87,721	162,481	1,305,609	14,855	3,965	2,958	5,489
LA	88,090	143,418	1,101,942	13,217	3,539	2,633	4,965
ME	23,393	39,995	408,123	3,272	919	657	1,536
MD	98,130	169,676	1,506,086	14,936	4,079	2,977	6,300
MA	98,049	163,181	1,506,407	13,698	3,826	2,766	6,155
MI	195,148	327,905	3,101,987	28,244	7,678	5,642	11,497
MN	108,776	187,307	1,846,778	16,260	4,376	3,238	6,313
MS	66,169	121,486	818,329	12,147	3,161	2,436	3,646
MO	130,174	227,899	1,983,729	20,352	5,475	4,051	7,906
MT	18,942	38,692	336,859	3,564	937	709	1,199
NE	34,806	64,232	554,573	5,779	1,540	1,152	2,104
NV	40,924	69,298	634,935	5,985	1,643	1,199	2,539
NH	23,398	45,160	411,806	4,087	1,089	813	1,501
NJ	131,703	208,293	1,951,564	17,898	4,974	3,586	8,132
NM	50,131	88,414	736,821	8,154	2,167	1,625	2,919
NY	247,324	403,657	3,629,204	34,800	9,578	6,964	15,076
NC	208,880	327,332	2,742,634	29,773	8,021	5,942	11,531
ND	14,058	26,310	249,772	2,381	628	474	815
OH	212,927	347,623	3,256,194	30,277	8,216	6,040	12,271
OK	87,307	151,444	1,199,549	13,844	3,726	2,760	5,348
OR	77,456	135,526	1,237,689	12,047	3,245	2,394	4,732
PA	200,988	344,115	3,005,254	30,520	8,248	6,093	12,023
RI	16,392	25,845	254,506	2,100	589	421	997
SC	103,879	172,920	1,410,216	16,027	4,258	3,190	5,763
SD	16,107	31,596	285,045	2,895	761	575	977
TN	141,401	226,122	1,949,990	20,180	5,446	4,029	7,884
TX	489,910	768,280	6,178,976	68,075	18,612	13,592	28,680
UT	51,355	83,181	783,937	7,172	1,967	1,437	3,024
VT	13,273	26,081	231,885	2,384	629	474	823
VA	150,454	220,961	2,197,966	17,593	5,039	3,495	9,551
WA	117,789	191,099	1,792,178	16,482	4,510	3,289	6,998
WV	30,366	54,544	466,545	4,756	1,312	960	1,997
WI	109,935	203,601	1,845,178	18,288	4,896	3,647	6,838
WY	14,823	30,389	263,724	2,764	729	550	949
National	**5,734,012**	**9,105,919**	**80,491,386**	**797,345**	**229,246**	**169,690**	**336,083**

Table A-26. Onroad with CAAA Scenario – State Emissions Summary (tons per year)
Year = 2010

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	56,205	80,338	817,306	584	2,758	1,651	6,217
AZ	57,785	98,904	743,063	689	3,462	2,196	7,032
AR	29,836	52,372	489,958	348	1,774	1,127	3,593
CA	209,815	421,277	2,055,711	1,855	18,877	11,858	36,139
CO	43,913	66,427	805,320	504	2,313	1,405	5,424
CT	22,164	39,961	453,015	335	1,545	848	3,605
DE	7,219	12,953	126,268	98	474	294	1,042
DC	2,819	4,156	44,171	36	153	90	394
FL	206,430	259,871	2,601,463	1,890	8,739	5,319	20,385
GA	106,070	176,756	1,659,243	1,283	6,250	3,897	13,523
ID	14,578	25,735	267,442	168	854	542	1,741
IL	89,511	152,160	1,675,114	1,110	5,205	3,189	11,896
IN	71,513	118,985	1,255,399	802	3,968	2,489	8,409
IA	28,360	49,681	527,308	322	1,635	1,038	3,330
KS	27,945	46,598	481,647	314	1,551	973	3,285
KY	44,899	77,879	774,416	528	2,648	1,630	5,489
LA	43,047	68,835	626,683	476	2,369	1,491	4,965
ME	11,143	18,355	236,866	137	644	388	1,536
MD	41,095	72,707	764,599	590	2,784	1,508	6,300
MA	38,941	70,512	731,334	572	2,631	1,598	6,131
MI	92,869	152,541	1,831,972	1,084	5,200	3,061	11,497
MN	56,418	90,835	1,108,975	601	2,946	1,842	6,313
MS	29,271	57,168	451,440	340	2,041	1,343	3,646
MO	61,039	106,745	1,100,058	752	3,687	2,229	7,906
MT	9,945	18,859	203,268	118	617	395	1,199
NE	17,888	31,207	331,204	203	1,025	649	2,104
NV	20,733	32,205	362,802	237	1,118	687	2,539
NH	11,624	21,969	242,486	144	727	460	1,501
NJ	52,572	88,107	965,570	751	3,427	1,842	8,132
NM	26,746	43,058	450,533	282	1,439	914	2,919
NY	107,670	178,454	1,973,044	1,397	6,546	3,751	15,025
NC	87,430	146,919	1,352,113	1,097	5,390	3,334	11,531
ND	6,992	12,808	145,413	80	414	266	815
OH	95,559	155,694	1,778,406	1,158	5,566	3,195	12,271
OK	46,309	74,708	743,250	509	2,504	1,567	5,348
OR	38,220	64,841	701,075	464	2,190	1,364	4,732
PA	85,170	150,362	1,574,248	1,140	5,557	3,137	12,023
RI	6,434	10,864	124,891	91	409	229	997
SC	49,138	83,883	783,037	557	2,832	1,798	5,763
SD	8,180	15,369	165,672	96	501	322	977
TN	61,914	104,723	1,036,958	747	3,664	2,243	7,884
TX	232,578	357,901	3,510,780	2,686	12,684	7,624	28,680
UT	24,904	38,968	448,984	282	1,339	823	3,024
VT	5,572	11,418	115,854	80	416	266	823
VA	74,707	101,715	1,306,635	842	3,612	2,062	9,551
WA	53,651	88,207	954,033	654	3,079	1,890	6,998
WV	14,465	24,406	277,781	175	897	530	1,997
WI	53,065	94,770	1,050,921	655	3,273	1,959	6,838
WY	7,855	14,842	160,238	93	481	308	949
National	**2,592,203**	**4,288,009**	**42,387,967**	**29,954**	**154,216**	**93,621**	**334,417**

Table A-27. Onroad without CAAA Scenario – State Emissions Summary (tons per year)
Year = 2020

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	134,688	188,932	1,600,051	17,447	4,254	3,054	6,972
AZ	160,114	266,544	1,815,576	26,682	6,211	4,562	9,134
AR	73,802	126,740	1,033,708	12,535	2,947	2,171	4,279
CA	772,390	946,249	10,178,487	78,325	48,744	40,220	46,159
CO	108,192	171,887	1,739,214	15,611	3,842	2,727	6,625
CT	66,520	109,872	1,087,545	9,630	2,376	1,690	4,065
DE	20,868	35,029	304,354	3,258	788	570	1,251
DC	7,532	10,389	96,193	836	217	150	417
FL	512,455	665,256	5,193,404	60,312	14,972	10,672	25,479
GA	286,914	457,913	3,810,743	43,910	10,564	7,668	16,516
ID	34,580	64,044	550,320	6,185	1,462	1,075	2,138
IL	222,969	367,358	3,520,149	32,192	7,915	5,669	13,168
IN	158,737	279,839	2,431,142	26,403	6,308	4,604	9,611
IA	64,630	111,362	1,040,184	10,627	2,510	1,846	3,677
KS	59,845	106,645	891,627	10,095	2,414	1,759	3,705
KY	98,979	181,981	1,481,765	17,611	4,174	3,060	6,210
LA	102,967	166,453	1,292,380	16,277	3,873	2,832	5,841
ME	25,949	45,047	453,839	3,940	987	697	1,707
MD	116,878	201,362	1,809,039	18,696	4,557	3,271	7,488
MA	112,974	185,911	1,748,562	16,358	4,097	2,915	6,994
MI	220,217	370,147	3,530,860	33,527	8,120	5,868	12,967
MN	124,110	214,091	2,127,163	19,628	4,703	3,420	7,285
MS	69,056	129,517	858,707	14,095	3,201	2,443	3,819
MO	147,788	257,652	2,265,998	24,301	5,813	4,230	8,969
MT	22,214	45,056	397,809	4,409	1,026	762	1,420
NE	39,014	71,312	624,458	6,768	1,604	1,178	2,374
NV	54,334	90,647	847,278	8,213	2,017	1,446	3,344
NH	28,144	53,650	500,062	5,137	1,216	892	1,805
NJ	154,186	241,926	2,310,159	21,755	5,419	3,842	9,407
NM	61,194	106,748	901,452	10,440	2,461	1,814	3,573
NY	278,572	451,815	4,113,304	40,972	10,089	7,211	16,938
NC	254,941	396,746	3,365,001	38,015	9,124	6,638	14,115
ND	15,391	28,647	276,168	2,741	641	475	903
OH	234,582	384,177	3,616,778	35,430	8,569	6,193	13,662
OK	101,573	175,491	1,403,139	16,992	4,071	2,963	6,279
OR	98,502	169,908	1,585,802	15,800	3,811	2,752	6,076
PA	229,769	391,169	3,462,637	36,479	8,774	6,373	13,681
RI	19,042	29,683	297,477	2,496	629	442	1,129
SC	125,150	205,968	1,705,201	20,255	4,777	3,515	6,986
SD	18,026	34,994	321,400	3,401	792	588	1,104
TN	162,788	258,539	2,260,163	24,400	5,859	4,262	9,074
TX	604,955	941,781	7,659,396	88,040	21,517	15,439	35,460
UT	64,511	103,664	990,369	9,558	2,339	1,684	3,803
VT	15,572	30,471	274,419	2,951	690	511	976
VA	177,231	260,230	2,600,367	21,797	5,638	3,845	11,260
WA	147,409	237,738	2,254,651	21,470	5,254	3,764	8,717
WV	31,802	58,033	489,833	5,490	1,343	974	2,094
WI	125,643	232,607	2,129,530	22,079	5,250	3,844	7,871
WY	16,842	34,200	301,682	3,314	774	574	1,089
National	**6,784,539**	**10,695,419**	**95,549,545**	**986,882**	**268,733**	**199,153**	**397,618**

Table A-28. Onroad with CAAA Scenario – State Emissions Summary (tons per year)
Year = 2020

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	34,491	34,974	686,205	675	2,240	1,104	6,972
AZ	39,115	44,182	691,822	920	3,097	1,564	9,134
AR	20,049	23,627	434,920	426	1,451	732	4,279
CA	134,619	225,483	1,124,224	2,373	21,601	13,695	43,870
CO	28,280	29,091	724,825	634	2,078	1,028	6,625
CT	12,513	14,966	371,326	388	1,279	615	4,065
DE	4,426	5,116	109,541	122	407	203	1,251
DC	1,526	1,503	34,666	39	125	61	417
FL	142,711	129,309	2,420,605	2,432	8,017	3,971	25,479
GA	68,610	76,061	1,478,156	1,612	5,406	2,705	16,516
ID	10,076	11,878	245,498	212	722	364	2,138
IL	52,107	59,852	1,379,170	1,264	4,188	2,080	13,168
IN	45,460	51,447	1,078,243	944	3,183	1,597	9,611
IA	17,740	20,891	437,904	365	1,241	625	3,677
KS	17,818	20,232	407,769	363	1,223	613	3,705
KY	28,476	33,350	658,479	614	2,081	1,037	6,210
LA	27,709	29,931	539,289	575	1,944	977	5,841
ME	7,040	8,085	201,095	158	540	268	1,707
MD	25,204	29,846	663,099	722	2,398	1,143	7,488
MA	22,804	26,520	624,012	675	2,205	1,093	6,991
MI	55,452	64,011	1,560,737	1,259	4,203	2,057	12,967
MN	36,731	40,829	964,921	713	2,396	1,200	7,285
MS	16,923	21,171	348,872	371	1,425	736	3,819
MO	37,889	44,947	933,400	879	2,956	1,463	8,969
MT	6,710	8,418	180,445	143	493	250	1,420
NE	11,441	13,438	280,811	235	797	401	2,374
NV	14,028	14,017	346,040	321	1,065	529	3,344
NH	8,117	10,263	221,371	179	606	305	1,805
NJ	30,504	34,024	811,391	894	2,937	1,397	9,407
NM	18,648	19,745	411,146	355	1,211	611	3,573
NY	67,582	76,843	1,687,592	1,624	5,368	2,596	16,932
NC	53,104	57,766	1,159,040	1,381	4,642	2,315	14,115
ND	4,393	5,373	120,755	91	310	157	903
OH	54,814	61,573	1,465,605	1,327	4,433	2,153	13,662
OK	30,680	33,846	654,231	615	2,068	1,037	6,279
OR	26,484	30,088	663,799	607	1,977	987	6,076
PA	51,213	60,378	1,306,128	1,336	4,483	2,167	13,681
RI	3,732	4,235	104,760	107	348	169	1,129
SC	33,540	38,479	707,534	694	2,360	1,190	6,986
SD	5,243	6,531	140,450	111	382	193	1,104
TN	37,225	42,629	877,678	885	2,982	1,482	9,074
TX	150,369	159,439	3,198,831	3,416	11,336	5,611	35,460
UT	16,511	17,010	409,525	367	1,222	609	3,803
VT	3,246	4,161	96,954	98	335	170	976
VA	48,593	48,743	1,154,156	1,023	3,330	1,609	11,260
WA	34,504	37,552	858,460	838	2,779	1,381	8,717
WV	8,047	9,391	218,768	191	688	340	2,094
WI	33,562	40,293	907,443	776	2,627	1,306	7,871
WY	5,139	6,425	137,819	109	375	190	1,089
National	**1,645,197**	**1,887,967**	**36,239,508**	**36,457**	**135,559**	**70,086**	**395,319**

Table A-29. Nonpoint – State Emissions Summary (tons per year)
Year = 1990

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$[3]	NH_3
AL	272,592	85,018	884,801	79,872	427,802	not estimated	71,494
AZ	138,462	90,281	795,387	10,360	293,089	not estimated	36,545
AR	122,761	72,114	244,374	22,467	257,736	not estimated	97,070
CA	861,096	340,060	1,191,628	73,731	1,277,147	not estimated	125,706
CO	178,217	65,662	722,233	83,601	368,989	not estimated	66,129
CT	234,012	16,707	252,414	16,235	98,991	not estimated	7,434
DE	33,159	13,162	34,508	8,951	24,735	not estimated	11,773
DC	10,623	1,765	2,094	2,617	10,658	not estimated	922
FL	360,988	85,975	746,961	46,012	620,273	not estimated	63,257
GA	229,901	79,056	487,643	9,751	641,713	not estimated	70,906
ID	67,510	22,711	188,503	8,416	93,238	not estimated	42,920
IL	357,653	267,524	163,376	44,594	863,958	not estimated	121,548
IN	242,215	115,612	157,412	205,041	597,870	not estimated	101,184
IA	146,266	60,034	160,526	14,128	439,401	not estimated	295,685
KS	201,833	126,609	1,012,701	16,910	1,206,094	not estimated	102,852
KY	157,504	134,711	205,982	52,626	206,098	not estimated	44,533
LA	198,265	253,038	479,294	122,982	325,088	not estimated	61,488
ME	159,526	15,445	203,097	21,228	238,557	not estimated	8,203
MD	193,483	52,885	247,481	101,642	174,857	not estimated	28,932
MA	270,686	49,744	226,555	48,410	298,791	not estimated	15,448
MI	333,376	149,296	153,594	62,640	468,289	not estimated	71,606
MN	237,764	80,378	307,012	11,922	762,953	not estimated	66,321
MS	169,957	93,557	212,986	84,462	320,905	not estimated	54,657
MO	225,589	98,986	353,378	35,910	982,872	not estimated	115,566
MT	52,939	69,558	130,198	5,029	334,659	not estimated	37,015
NE	80,291	84,952	103,669	11,697	463,366	not estimated	161,294
NV	33,597	17,057	50,834	3,895	94,198	not estimated	6,135
NH	102,549	9,995	128,899	47,151	43,577	not estimated	2,864
NJ	250,496	141,509	189,814	132,857	232,757	not estimated	16,632
NM	81,015	61,912	637,573	11,702	1,464,190	not estimated	24,658
NY	1,143,425	199,576	1,113,316	172,785	506,228	not estimated	80,141
NC	295,751	45,207	484,026	28,539	329,546	not estimated	93,213
ND	57,366	39,635	50,285	53,262	351,231	not estimated	62,962
OH	326,316	197,630	257,532	82,554	528,059	not estimated	100,724
OK	153,029	130,575	443,906	23,254	670,521	not estimated	85,161
OR	428,643	135,164	471,903	35,143	571,398	not estimated	46,636
PA	334,277	191,992	342,605	104,075	430,063	not estimated	80,713
RI	27,785	7,276	12,344	8,760	22,144	not estimated	744
SC	242,632	33,158	334,424	15,148	293,948	not estimated	32,480
SD	49,065	11,410	124,621	12,633	269,145	not estimated	85,074
TN	244,035	101,887	231,344	46,868	234,008	not estimated	37,648
TX	690,194	390,029	715,781	62,093	2,877,889	not estimated	331,664
UT	75,479	40,448	140,226	13,635	92,045	not estimated	18,601
VT	36,655	13,785	66,211	7,866	56,745	not estimated	9,806
VA	315,731	96,350	333,823	175,432	282,151	not estimated	43,356
WA	291,574	123,906	412,309	21,916	434,380	not estimated	41,153
WV	70,635	75,027	100,514	49,110	92,662	not estimated	15,595
WI	333,126	91,371	309,921	29,848	421,175	not estimated	143,743
WY	32,762	89,102	179,086	15,018	398,859	not estimated	16,954
National	**11,152,804**	**4,768,841**	**16,799,105**	**2,354,778**	**22,495,048**	**4,198,487**	**3,257,139**

[3] The project team determined that the 1990 NEI did not accurately measure $PM_{2.5}$ emissions. The project team estimated revised state-level $PM_{2.5}$ emissions for 2000, 2010, and 2020, as well as revised National emissions for 1990, but did not develop revised state-level emissions estimates for 1990.

Table A-30. Nonpoint without CAAA Scenario – State Emissions Summary (tons per year)
Year = 2000

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	276,944	97,719	869,187	77,011	444,123	115,004	76,514
AZ	189,810	91,915	807,977	11,427	368,804	95,414	40,023
AR	147,234	75,859	244,011	6,238	244,299	75,122	119,370
CA	1,082,151	250,068	1,061,363	43,759	1,334,218	208,013	161,887
CO	212,675	87,135	704,772	83,460	477,855	96,162	76,722
CT	217,873	17,156	198,274	15,466	109,502	18,113	6,998
DE	36,087	16,242	33,023	11,734	29,738	7,182	12,665
DC	11,549	1,991	1,831	2,208	12,753	1,374	1,089
FL	452,389	91,321	770,392	31,817	708,482	117,488	68,278
GA	287,216	85,852	512,189	8,944	661,459	140,368	84,131
ID	74,920	26,936	190,765	8,431	116,509	68,282	58,557
IL	415,160	230,291	135,230	26,956	895,435	136,524	121,424
IN	294,352	108,133	143,468	177,656	596,448	122,339	98,684
IA	164,248	57,280	140,989	15,893	446,427	87,375	268,692
KS	207,311	112,716	934,432	16,113	1,218,128	176,167	113,440
KY	174,710	136,403	190,313	39,043	222,822	54,223	52,066
LA	224,423	265,230	489,029	135,355	369,079	75,415	74,417
ME	138,699	14,765	156,555	15,238	235,312	106,074	8,907
MD	204,314	54,079	233,938	67,766	206,470	33,633	27,028
MA	276,670	48,280	176,554	29,892	308,144	50,170	15,339
MI	400,883	146,039	134,468	45,985	489,051	78,454	70,966
MN	267,620	73,222	273,309	9,113	808,863	125,658	78,719
MS	193,541	92,015	211,241	11,004	305,462	69,051	70,360
MO	251,714	87,307	313,391	24,962	1,060,712	140,473	126,970
MT	56,540	83,788	123,424	5,170	320,566	58,380	45,102
NE	89,148	78,584	94,486	10,530	477,659	70,426	170,488
NV	47,781	17,987	54,065	4,102	134,612	23,255	6,373
NH	92,551	9,712	98,246	50,202	45,638	18,845	2,715
NJ	257,411	174,426	158,456	128,224	241,381	28,769	17,503
NM	93,161	72,843	637,794	13,029	1,402,008	138,907	36,874
NY	1,008,667	220,810	866,894	141,650	500,270	142,473	78,169
NC	368,127	51,797	512,659	20,403	371,364	94,973	156,020
ND	57,176	41,473	42,739	54,666	342,965	75,180	72,415
OH	383,271	182,644	226,876	51,231	558,832	96,426	110,432
OK	173,818	111,333	467,852	25,051	583,243	126,966	116,047
OR	400,964	111,367	361,779	40,037	528,461	236,879	51,799
PA	360,461	136,550	293,980	86,291	420,562	89,028	84,308
RI	32,903	7,015	9,708	7,849	25,014	2,793	813
SC	260,005	33,925	317,451	13,527	295,754	57,981	38,781
SD	51,871	13,448	117,905	29,225	270,987	58,373	97,571
TN	290,189	99,895	224,029	43,063	271,106	58,865	37,451
TX	826,297	393,225	706,805	61,112	2,825,024	360,448	375,956
UT	98,271	46,066	142,118	11,511	145,681	29,538	24,902
VT	36,768	15,478	52,958	10,309	55,227	12,389	9,539
VA	342,935	96,205	314,305	137,505	309,595	151,794	49,156
WA	292,129	79,479	358,884	13,520	436,106	76,958	43,686
WV	73,736	75,721	90,679	51,266	90,583	25,746	17,263
WI	336,714	136,980	259,296	130,664	433,397	76,042	125,926
WY	35,225	91,650	174,105	15,699	362,729	57,656	19,315
National	**12,268,609**	**4,650,355**	**15,634,196**	**2,071,308**	**23,118,860**	**4,367,172**	**3,621,848**

Table A-31. Nonpoint with CAAA Scenario – State Emissions Summary (tons per year)
Year = 2000

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	240,301	81,419	821,832	60,791	404,172	115,233	74,045
AZ	112,155	50,662	769,157	8,448	275,311	92,645	38,063
AR	111,784	65,589	337,975	31,879	266,086	74,624	121,382
CA	482,735	298,226	949,570	117,653	585,454	191,235	167,901
CO	103,407	36,283	664,830	86,460	295,149	89,409	73,007
CT	145,254	17,325	147,415	19,163	48,484	14,667	5,469
DE	15,473	13,724	16,243	9,340	13,562	3,680	12,846
DC	3,873	2,316	1,897	1,597	6,203	1,025	13
FL	469,364	90,538	784,496	79,653	397,323	118,210	55,965
GA	303,342	86,261	528,435	61,922	640,122	132,370	81,966
ID	140,931	39,875	211,929	3,471	342,674	69,461	64,060
IL	276,627	164,281	114,592	16,570	696,887	127,369	108,356
IN	177,935	81,404	90,781	65,117	619,427	114,020	97,177
IA	78,134	40,886	102,728	21,910	477,728	86,062	258,231
KS	135,769	73,967	873,048	38,237	728,425	175,025	113,974
KY	105,477	79,639	143,891	43,196	233,319	52,614	51,147
LA	153,346	227,053	454,570	33,217	238,221	72,648	70,762
ME	87,678	9,136	107,741	10,165	61,241	19,541	7,771
MD	127,931	37,811	160,837	46,469	102,270	30,331	25,168
MA	177,371	48,649	162,558	57,741	195,577	45,258	12,374
MI	238,631	83,927	128,711	56,105	415,863	75,110	64,597
MN	127,273	105,721	233,404	20,721	740,596	125,818	73,245
MS	159,191	79,672	171,423	16,050	351,538	65,739	70,233
MO	166,665	100,236	253,015	51,511	962,242	140,326	122,253
MT	27,729	48,848	105,621	4,906	342,012	57,519	46,233
NE	42,274	65,511	85,704	32,584	451,418	69,773	173,321
NV	23,012	16,680	45,307	13,320	110,989	17,890	5,886
NH	61,058	13,245	80,742	7,685	43,226	17,551	2,205
NJ	148,622	46,191	101,858	22,872	61,176	17,866	15,594
NM	64,390	47,112	627,108	7,808	849,019	137,999	39,036
NY	743,008	158,481	636,715	126,096	433,780	123,897	67,105
NC	280,781	52,446	739,227	24,432	291,214	83,963	158,861
ND	15,589	56,340	46,429	124,008	406,843	74,880	71,494
OH	278,483	134,837	179,375	30,365	465,017	89,870	109,319
OK	200,782	115,394	451,548	9,102	711,524	127,313	113,407
OR	387,508	117,882	353,028	13,741	518,182	231,467	54,546
PA	277,349	113,019	290,523	75,384	393,149	78,454	80,375
RI	11,947	3,843	8,514	3,443	7,998	2,000	251
SC	188,661	39,298	289,309	32,329	278,564	58,110	37,721
SD	22,946	10,075	104,325	10,947	286,231	57,868	102,348
TN	146,509	68,308	157,291	38,886	234,848	53,333	34,487
TX	720,854	514,714	934,794	137,312	2,362,922	356,783	387,490
UT	65,822	23,313	150,796	4,491	92,701	25,875	26,301
VT	18,505	3,487	44,326	5,391	55,791	10,905	9,054
VA	201,099	91,873	239,836	132,324	744,649	155,078	45,666
WA	166,822	101,260	267,987	20,694	271,526	72,575	44,078
WV	58,630	46,759	79,507	20,321	111,960	24,927	16,311
WI	227,951	52,366	202,207	11,178	295,607	67,594	121,192
WY	23,368	29,823	160,814	8,278	411,631	57,337	19,286
National	**8,544,345**	**3,885,707**	**14,613,968**	**1,875,282**	**19,329,848**	**4,103,247**	**3,551,567**

Table A-32. Nonpoint without CAAA Scenario – State Emissions Summary (tons per year)
Year = 2010

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	286,227	100,891	853,667	79,016	393,498	107,831	82,539
AZ	230,971	103,797	817,255	11,951	395,072	97,016	47,740
AR	168,074	93,581	244,248	62,670	233,427	76,299	133,532
CA	1,282,360	288,509	973,804	53,907	1,453,754	203,285	188,570
CO	240,858	78,970	686,652	83,856	497,752	102,827	69,966
CT	211,600	15,437	158,507	16,102	109,132	19,981	6,414
DE	40,760	16,209	32,279	17,876	31,557	8,198	13,873
DC	12,779	2,155	1,632	2,681	13,266	1,556	1,284
FL	551,157	103,357	780,597	40,050	748,692	122,027	71,071
GA	342,836	98,463	529,530	10,166	670,825	143,659	95,415
ID	80,913	24,561	195,175	9,937	125,743	64,255	75,147
IL	455,166	230,424	115,936	34,704	861,803	130,452	131,383
IN	332,571	108,255	134,773	192,508	605,460	118,892	105,748
IA	179,756	58,170	124,574	17,027	431,170	84,657	278,704
KS	215,336	108,292	878,755	16,711	1,202,231	174,088	115,765
KY	192,641	134,678	175,360	42,332	202,161	53,544	59,168
LA	257,084	294,062	484,544	258,811	361,647	78,607	82,191
ME	124,527	14,818	120,330	13,728	234,506	111,466	8,927
MD	226,814	62,248	236,453	77,919	213,757	37,415	28,434
MA	284,390	43,053	139,449	28,234	306,112	54,978	15,694
MI	443,311	149,423	134,310	51,116	502,394	78,939	73,399
MN	292,774	74,311	246,200	10,147	813,938	128,239	80,753
MS	209,258	107,642	205,124	45,457	260,086	62,418	80,287
MO	275,206	87,312	280,498	30,093	1,087,786	149,102	130,246
MT	59,876	65,546	114,610	4,173	291,388	51,381	45,817
NE	98,348	78,068	87,221	13,883	473,919	70,616	170,809
NV	59,735	22,104	55,762	4,134	146,874	25,243	6,305
NH	86,233	19,161	79,442	111,683	47,537	21,686	2,353
NJ	268,511	152,659	127,738	103,784	246,455	29,564	18,352
NM	106,139	88,879	638,624	24,340	1,303,699	114,989	45,819
NY	919,084	201,573	660,883	136,423	497,959	139,896	75,912
NC	433,289	59,839	523,228	20,948	382,436	100,233	174,522
ND	60,403	43,688	37,389	58,569	320,236	71,967	71,711
OH	428,851	183,439	210,103	56,782	547,512	95,716	115,425
OK	195,706	110,595	447,562	28,282	532,972	122,373	126,078
OR	383,711	120,639	258,313	41,404	505,048	249,292	54,763
PA	397,012	129,699	270,795	93,475	412,961	89,019	86,475
RI	38,569	6,186	8,791	7,101	25,434	2,991	863
SC	290,997	36,744	307,132	14,554	297,659	58,505	43,687
SD	54,655	12,481	111,478	23,523	260,371	56,581	101,223
TN	326,670	106,698	218,132	48,329	254,823	59,994	39,797
TX	971,590	440,301	691,809	64,147	2,694,499	352,958	393,345
UT	117,678	41,096	151,789	11,732	165,303	32,300	26,579
VT	36,637	14,724	41,972	12,125	54,110	13,525	8,137
VA	386,271	102,049	318,180	129,876	321,386	155,831	50,470
WA	309,060	97,854	323,682	15,019	454,626	79,574	43,033
WV	82,956	74,012	83,465	39,482	89,702	26,392	17,568
WI	338,026	148,220	219,635	161,280	421,306	82,525	113,508
WY	38,099	85,863	170,278	21,940	312,394	45,472	19,668
National	**13,425,477**	**4,840,735**	**14,707,662**	**2,453,986**	**22,816,379**	**4,358,354**	**3,828,468**

Table A-33. Nonpoint with CAAA Scenario – State Emissions Summary (tons per year)[4]
Year = 2010

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	251,455	77,240	813,929	66,485	367,436	111,889	80,136
AZ	119,984	45,534	773,435	7,706	282,332	94,338	45,375
AR	124,859	57,965	342,226	30,908	264,583	74,741	133,636
CA	372,684	269,113	939,367	104,757	565,554	183,874	188,367
CO	111,069	33,725	685,580	86,375	296,706	92,660	67,616
CT	120,741	17,281	134,267	19,838	48,657	14,271	5,095
DE	13,693	14,713	15,007	9,211	14,282	3,766	13,688
DC	3,355	2,473	1,974	1,663	6,467	1,087	14
FL	485,318	91,464	802,954	86,740	412,005	123,150	57,375
GA	348,195	82,743	549,970	63,196	642,107	135,192	90,889
ID	178,710	43,128	219,476	2,899	316,416	70,383	76,411
IL	256,339	136,235	109,403	13,001	650,405	116,829	114,318
IN	188,621	70,148	85,907	60,174	592,205	106,931	102,849
IA	82,370	33,807	96,580	22,714	459,805	81,225	273,982
KS	138,478	63,424	866,647	39,419	716,700	170,184	115,686
KY	111,044	75,931	141,034	43,141	222,420	51,758	54,677
LA	170,484	233,811	460,570	31,287	237,605	73,123	78,789
ME	81,774	9,938	83,827	11,516	60,907	18,908	7,981
MD	111,579	37,406	156,894	44,014	105,162	30,989	26,092
MA	164,481	48,252	141,716	58,498	195,221	45,923	12,639
MI	237,846	87,166	136,272	54,934	410,561	73,692	66,202
MN	127,920	105,214	228,687	20,781	742,666	124,212	73,301
MS	147,860	74,484	170,921	15,452	311,117	61,023	78,036
MO	178,557	90,054	240,741	54,087	997,338	142,762	124,699
MT	28,362	44,743	103,690	3,088	311,767	53,917	47,058
NE	44,316	46,658	84,092	33,248	449,819	67,046	172,520
NV	25,990	15,459	48,154	14,051	118,752	19,429	5,730
NH	56,893	14,307	66,874	8,225	44,855	17,958	2,031
NJ	75,778	46,082	85,795	24,001	62,918	17,044	16,140
NM	67,471	37,851	628,054	6,875	747,089	128,045	44,706
NY	638,070	158,453	505,475	123,000	417,797	117,470	65,733
NC	302,789	50,471	791,155	26,079	299,858	86,788	170,538
ND	15,563	53,567	45,996	136,098	389,738	70,632	69,969
OH	289,596	121,579	167,568	29,128	448,761	85,624	113,646
OK	206,914	109,162	458,419	8,487	693,689	125,394	122,291
OR	426,281	116,355	448,479	14,071	489,090	241,102	56,590
PA	238,353	111,284	292,389	75,803	387,488	77,552	81,826
RI	12,465	3,740	8,250	3,526	8,215	2,074	244
SC	170,920	37,907	295,802	34,288	277,807	58,971	42,038
SD	23,500	9,360	101,790	11,806	275,729	55,345	102,159
TN	154,697	63,576	156,071	38,007	228,653	52,952	35,232
TX	752,153	505,468	961,050	135,758	2,346,634	356,402	400,249
UT	73,495	20,077	156,440	3,717	101,731	27,902	26,596
VT	18,223	3,758	45,560	6,108	55,715	11,306	7,866
VA	200,647	91,505	234,314	133,458	753,364	157,139	48,341
WA	171,283	98,531	265,046	20,025	255,394	73,054	44,773
WV	59,699	45,167	78,982	21,301	114,766	25,636	16,636
WI	223,896	47,157	218,552	10,854	286,871	68,615	112,822
WY	24,344	21,473	159,726	7,833	359,784	52,024	19,577
National	**8,429,115**	**3,674,940**	**14,605,108**	**1,877,630**	**18,844,942**	**4,052,330**	**3,713,161**

[4] $PM_{2.5}$ emission totals reflect reductions from local controls implemented on both nonpoint sources and on nonroad vehicles for compliance with the $PM_{2.5}$ NAAQS. Emission totals in Chapter 1 do not reflect reductions from $PM_{2.5}$ NAAQS local controls for the nonroad vehicles and therefore do not match the totals presented here.

Table A-34. Nonpoint without CAAA Scenario – State Emissions Summary (tons per year)
Year = 2020

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	317,286	106,230	857,665	80,965	373,370	110,041	92,797
AZ	296,527	116,129	835,410	12,554	461,642	104,514	56,821
AR	203,224	115,499	253,857	160,543	240,712	80,966	150,427
CA	1,625,701	306,343	1,021,061	56,507	1,762,922	224,933	218,706
CO	298,537	89,875	691,160	84,141	592,636	117,572	73,819
CT	236,097	15,930	160,303	16,039	124,523	21,616	6,703
DE	48,296	17,332	34,454	19,567	37,120	9,334	16,230
DC	14,800	2,433	1,634	3,208	15,907	1,863	1,642
FL	671,593	112,840	811,774	44,337	851,740	131,320	78,301
GA	417,279	108,724	562,779	11,256	699,707	154,955	109,868
ID	98,420	27,036	208,455	10,481	151,423	73,585	88,996
IL	523,245	239,114	116,873	39,718	931,621	135,224	147,432
IN	388,372	113,300	138,638	192,656	648,378	119,746	117,852
IA	203,861	61,677	123,450	17,533	452,758	87,321	298,191
KS	236,913	114,165	895,895	17,599	1,233,343	178,530	119,362
KY	218,628	144,789	178,941	45,208	204,066	56,619	63,149
LA	305,315	356,216	500,798	645,323	397,750	88,003	96,165
ME	133,869	14,848	115,084	14,016	240,127	112,491	9,558
MD	268,852	68,284	255,299	79,601	254,775	43,050	31,360
MA	326,056	44,626	135,470	28,313	331,762	59,524	17,185
MI	511,402	154,014	145,306	55,551	547,856	80,696	77,887
MN	334,957	78,172	246,636	10,767	866,992	132,138	83,196
MS	235,935	116,105	208,990	58,260	232,933	65,028	89,331
MO	315,813	92,468	281,838	30,919	1,161,552	153,269	136,240
MT	68,709	70,655	116,339	4,324	278,526	54,885	47,274
NE	111,067	82,149	87,957	14,233	497,305	72,142	177,566
NV	76,412	24,923	60,416	4,470	181,601	32,065	6,515
NH	93,324	18,662	76,072	107,586	52,492	23,075	2,236
NJ	302,597	158,185	123,014	110,743	270,518	30,826	19,966
NM	124,984	98,511	643,683	27,838	1,210,918	119,895	50,148
NY	961,125	200,992	608,404	137,699	524,346	135,995	76,948
NC	530,549	66,180	567,178	21,439	435,441	110,387	197,000
ND	65,363	45,744	36,916	58,032	331,900	73,469	72,710
OH	496,329	194,029	220,862	63,483	595,821	100,668	124,824
OK	231,708	120,724	468,854	33,647	524,922	127,327	136,238
OR	423,240	125,039	251,693	46,080	508,496	272,209	56,478
PA	454,638	133,701	271,278	96,333	432,466	92,941	90,849
RI	46,528	6,396	8,954	7,261	29,031	3,205	1,025
SC	340,789	39,446	321,340	15,315	307,579	62,042	48,608
SD	60,074	12,828	110,919	23,666	272,390	58,206	103,786
TN	374,337	112,595	226,582	52,721	269,729	64,133	42,156
TX	1,170,720	471,453	714,632	80,797	2,747,807	371,421	412,897
UT	148,067	45,768	166,660	11,905	215,225	38,348	27,419
VT	41,399	14,436	40,269	12,198	57,205	14,336	7,149
VA	457,343	109,336	356,648	132,094	358,894	159,733	56,137
WA	368,763	104,669	348,210	15,880	538,642	90,761	44,219
WV	97,382	80,012	85,045	42,130	91,637	28,465	18,695
WI	382,550	149,187	223,206	165,394	444,899	91,366	107,506
WY	43,706	96,511	171,713	23,917	262,412	47,544	21,046
National	**15,702,681**	**5,198,279**	**15,088,612**	**3,044,248**	**24,255,816**	**4,617,781**	**4,130,614**

Table A-35. Nonpoint with CAAA Scenario – State Emissions Summary (tons per year)
Year = 2020[5]

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	265,525	79,104	826,803	75,999	330,515	109,597	89,979
AZ	135,448	46,990	785,243	7,793	306,444	99,289	53,961
AR	145,707	59,545	358,579	32,167	262,475	76,621	150,128
CA	439,110	268,884	1,003,081	112,308	575,612	190,177	218,133
CO	123,299	35,955	722,918	86,675	328,302	101,478	71,126
CT	119,646	17,336	140,409	19,828	50,851	13,791	5,034
DE	14,503	16,262	16,781	10,258	15,999	4,043	15,979
DC	3,671	2,639	2,166	1,758	7,491	1,291	16
FL	574,504	96,373	842,368	97,624	434,815	131,176	62,075
GA	413,739	86,533	582,979	65,758	649,306	141,283	104,387
ID	233,175	49,966	241,704	2,639	291,286	73,675	90,703
IL	287,565	134,805	119,127	14,636	682,234	122,254	126,120
IN	220,453	69,479	92,497	55,429	619,437	108,758	114,557
IA	87,369	33,886	101,585	23,221	480,506	84,054	292,997
KS	143,209	63,007	886,803	39,897	751,052	175,772	119,046
KY	117,868	78,521	151,411	45,457	221,944	53,082	58,265
LA	196,341	239,150	476,974	37,801	243,635	76,226	90,476
ME	75,849	10,003	93,367	11,327	62,276	17,861	8,457
MD	126,707	39,776	176,803	43,546	117,031	33,084	28,575
MA	169,627	50,296	155,250	57,783	204,124	46,823	13,182
MI	262,630	95,017	146,660	54,709	436,874	77,070	68,944
MN	130,421	109,117	242,998	22,043	780,465	129,413	74,702
MS	159,265	75,798	175,360	18,041	278,537	58,887	86,782
MO	194,373	90,777	255,266	54,213	1,057,245	149,988	129,900
MT	30,372	42,953	108,319	2,930	289,299	52,926	48,971
NE	47,049	44,746	87,261	33,048	471,464	69,669	179,244
NV	31,396	16,924	52,971	14,879	138,752	22,896	5,805
NH	53,983	15,072	74,143	8,255	47,268	17,962	1,837
NJ	73,890	47,859	91,317	27,258	64,850	16,179	17,039
NM	74,244	38,036	633,589	6,995	622,857	117,314	48,918
NY	609,801	158,270	536,446	120,674	406,706	108,866	63,896
NC	342,899	52,286	853,630	27,363	328,154	94,262	192,267
ND	15,688	52,433	47,310	134,660	401,429	72,334	70,895
OH	327,279	121,766	184,689	31,573	478,556	90,073	122,691
OK	207,521	102,423	481,998	8,815	674,450	126,490	131,654
OR	473,563	118,944	534,365	15,840	451,642	249,519	58,836
PA	265,313	111,328	304,147	73,225	395,138	78,528	84,934
RI	13,972	3,857	8,833	3,435	9,085	2,229	249
SC	193,130	38,812	310,195	37,027	276,011	60,482	46,608
SD	24,196	9,344	103,680	11,969	286,838	57,040	104,689
TN	167,988	64,705	168,053	38,489	235,634	55,079	36,785
TX	784,564	481,074	968,412	143,317	2,327,381	362,786	418,796
UT	87,757	21,320	168,510	3,525	125,052	32,625	27,233
VT	18,050	3,893	51,409	6,392	57,738	11,627	6,846
VA	220,648	93,586	265,665	134,249	760,030	159,126	53,358
WA	182,823	104,701	320,659	23,303	255,505	78,159	46,334
WV	67,537	47,904	84,150	23,646	119,450	27,036	17,611
WI	242,680	49,398	253,218	11,781	308,418	74,178	106,703
WY	26,470	21,093	161,386	8,194	295,097	46,212	21,061
National	**9,222,786**	**3,711,949**	**15,451,487**	**1,941,752**	**19,015,260**	**4,159,288**	**3,986,783**

[5] $PM_{2.5}$ emission totals reflect reductions from local controls implemented on both nonpoint sources and on nonroad vehicles for compliance with the $PM_{2.5}$ NAAQS. Emission totals in Chapter 1 do not reflect reductions from $PM_{2.5}$ NAAQS local controls for the nonroad vehicles and therefore do not match the totals presented here.

Table A-36. State Totals – State Emissions Summary (tons per year)
Year = 1990

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$[6]	NH_3
AL	582,123	578,496	3,727,566	741,737	524,076	36,274	78,287
AZ	343,577	387,934	2,796,733	201,167	332,892	18,684	39,239
AR	261,579	262,553	1,684,767	115,348	307,936	21,240	113,631
CA	2,321,042	1,843,979	15,814,854	201,431	1,393,955	72,380	159,122
CO	368,699	342,841	2,827,263	194,309	414,477	22,693	68,435
CT	385,783	192,839	1,800,982	94,300	121,693	8,675	9,496
DE	82,718	95,203	448,255	99,651	31,132	3,964	12,957
DC	25,436	19,122	157,902	8,353	11,593	685	1,172
FL	1,100,036	932,477	7,602,691	803,730	710,657	65,681	78,139
GA	643,644	717,282	4,682,209	986,145	719,943	45,437	89,597
ID	129,960	94,468	866,329	37,028	115,644	6,463	43,670
IL	898,309	1,058,035	5,618,316	1,245,645	1,115,568	51,169	139,252
IN	613,711	945,472	3,718,669	1,941,081	750,023	51,612	112,396
IA	306,175	355,183	1,856,446	288,794	472,688	28,449	305,563
KS	380,885	476,115	2,641,711	151,950	1,262,281	23,784	117,156
KY	455,733	704,874	2,317,328	1,010,339	260,422	34,537	48,233
LA	489,666	797,057	2,852,291	419,384	410,761	34,453	125,920
ME	258,680	129,956	1,151,781	95,526	259,195	8,308	9,217
MD	429,655	404,225	2,846,646	427,035	201,118	17,892	32,341
MA	533,433	406,191	2,965,598	317,621	322,055	18,137	18,762
MI	977,266	910,961	5,838,517	706,565	577,120	41,712	78,148
MN	572,677	491,266	3,319,380	143,831	853,294	28,689	70,301
MS	374,859	345,171	1,844,161	272,032	349,852	19,950	81,525
MO	548,602	600,501	3,455,023	958,803	1,102,704	32,398	141,013
MT	110,352	180,385	742,844	74,960	368,623	12,239	38,051
NE	177,937	247,753	1,105,531	78,164	504,477	13,570	162,374
NV	101,219	129,719	778,640	65,520	115,521	7,958	6,917
NH	173,006	101,609	841,395	126,989	49,669	4,065	3,632
NJ	688,879	576,480	3,558,830	290,960	268,006	17,776	21,603
NM	186,560	308,804	1,855,631	181,924	1,491,147	14,918	25,910
NY	1,919,736	1,039,273	7,877,373	856,201	629,727	43,015	88,540
NC	756,154	629,191	4,386,688	465,512	378,437	33,652	97,777
ND	107,702	238,181	546,081	228,390	374,596	16,822	63,443
OH	959,531	1,288,575	6,624,620	2,709,030	653,989	57,073	109,568
OK	376,099	500,679	2,542,133	213,048	718,969	20,395	104,093
OR	598,093	330,239	2,289,268	70,740	629,123	15,229	48,693
PA	939,978	1,278,253	6,669,614	1,507,652	559,667	57,114	92,923
RI	74,729	47,059	442,405	14,487	25,799	1,635	1,314
SC	496,597	378,263	2,606,638	285,582	330,725	22,552	35,136
SD	96,277	109,945	645,391	49,187	280,262	8,421	85,617
TN	644,874	698,831	3,303,872	1,033,906	313,687	46,251	41,269
TX	1,809,503	2,150,408	10,582,382	1,045,013	3,101,272	110,442	345,059
UT	184,549	222,250	1,343,511	105,800	120,589	13,551	20,838
VT	73,487	49,464	477,259	10,915	59,161	1,935	10,251
VA	738,362	586,248	4,024,387	455,709	333,311	28,827	48,616
WA	572,195	431,982	3,539,089	142,352	475,094	18,041	48,767
WV	211,821	569,701	1,271,223	1,065,251	135,713	26,175	17,167
WI	622,453	466,303	3,028,448	462,335	498,462	24,712	147,464
WY	85,760	264,769	594,811	141,639	416,713	19,105	17,797
National	**25,790,101**	**25,916,562**	**154,513,482**	**23,143,066**	**25,453,815**	5,527,233	**3,656,388**

[6] State-level values do not include $PM_{2.5}$ emissions estimates for nonpoint sources, so state-level values do not sum to national values for this pollutant.

Table A-37. State Totals without CAAA Scenario – State Emissions Summary (tons per year)
Year = 2000

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	528,956	671,983	2,946,948	885,387	565,280	161,088	84,740
AZ	377,880	456,373	2,566,496	210,242	406,414	113,547	45,089
AR	263,714	270,888	1,423,931	103,634	301,265	93,052	139,215
CA	2,161,383	1,369,431	11,906,802	158,637	1,441,821	263,620	206,012
CO	389,187	429,984	2,526,853	228,520	528,090	115,647	81,340
CT	331,844	172,262	1,448,219	54,133	128,573	23,894	10,181
DE	77,170	85,877	361,066	83,912	37,895	11,663	14,199
DC	21,170	16,148	112,781	8,159	13,539	1,820	1,451
FL	1,115,614	987,157	6,517,651	787,589	805,544	184,419	89,681
GA	658,262	837,498	4,355,578	1,069,282	758,009	200,471	105,244
ID	127,294	102,110	760,203	49,902	144,062	74,137	59,911
IL	830,568	1,103,746	4,527,730	1,671,641	1,188,938	188,714	143,985
IN	631,564	1,064,306	3,386,345	2,114,038	793,819	195,096	114,220
IA	288,673	351,726	1,481,836	301,660	474,857	110,354	278,296
KS	349,218	450,094	2,142,475	143,885	1,271,785	195,617	126,678
KY	451,812	832,317	1,952,889	1,307,916	283,955	97,505	58,803
LA	507,786	793,342	2,645,664	496,868	462,403	106,966	150,032
ME	217,871	112,023	883,871	83,360	254,419	112,886	10,481
MD	382,062	407,875	2,297,993	447,666	248,051	66,067	32,488
MA	475,550	368,889	2,306,274	205,755	328,126	65,750	21,027
MI	961,250	919,253	4,525,330	759,752	613,345	124,246	81,330
MN	561,623	496,260	2,820,752	154,641	913,808	155,326	85,059
MS	373,897	347,429	1,442,599	198,710	336,021	88,370	90,973
MO	531,664	706,930	2,959,167	1,018,882	1,208,746	184,788	151,615
MT	99,749	200,848	599,935	77,393	359,135	69,408	46,461
NE	163,487	256,469	865,995	98,651	516,951	80,387	172,319
NV	112,299	159,822	795,419	92,121	158,900	31,484	8,172
NH	147,812	100,539	643,201	117,437	52,326	23,824	3,937
NJ	595,954	557,495	2,825,540	244,130	268,696	45,790	24,585
NM	171,028	338,620	1,519,905	165,874	1,425,598	151,661	39,181
NY	1,617,181	917,774	5,997,251	620,972	618,863	183,106	91,622
NC	796,473	815,380	3,931,015	663,371	437,075	144,725	165,104
ND	96,376	239,294	425,223	315,554	363,433	89,601	73,161
OH	908,135	1,369,447	5,557,298	3,028,708	736,234	199,911	124,148
OK	346,114	467,325	2,055,476	253,973	640,594	150,931	138,746
OR	542,444	312,718	1,934,503	80,924	601,076	250,241	55,265
PA	826,657	1,212,486	5,340,648	1,439,157	577,935	180,697	98,454
RI	65,125	39,424	341,233	11,801	28,406	4,093	1,670
SC	474,245	430,398	2,086,200	338,956	344,594	88,989	43,374
SD	84,759	104,344	507,045	68,306	279,321	64,056	98,419
TN	648,653	785,831	2,728,602	957,603	335,861	109,409	44,115
TX	1,837,196	2,268,051	8,882,176	1,245,032	3,045,223	448,610	401,353
UT	194,937	259,049	1,147,598	106,527	177,550	41,495	28,613
VT	62,869	46,060	346,386	14,416	57,132	13,758	10,220
VA	683,738	559,933	3,132,324	468,507	365,914	182,798	57,844
WA	505,096	361,842	2,768,448	141,754	472,882	92,085	52,786
WV	196,386	678,180	992,120	1,292,678	154,107	65,847	19,705
WI	603,262	576,612	2,849,544	585,241	514,001	99,163	133,690
WY	81,250	276,643	520,955	155,311	377,353	75,127	20,554
National	**24,477,238**	**26,688,484**	**127,093,493**	**25,128,567**	**26,417,926**	**5,822,241**	**4,135,550**

Table A-38. State Totals with CAAA Scenario – State Emissions Summary (tons per year)
Year = 2000

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	447,223	517,022	2,717,979	718,674	461,027	159,947	81,637
AZ	254,680	338,069	2,249,144	85,954	299,847	110,128	43,185
AR	232,233	262,078	1,364,725	133,864	290,013	92,578	125,553
CA	1,227,632	1,207,500	9,081,006	191,397	654,468	242,830	201,806
CO	313,568	304,802	2,226,389	213,229	324,830	108,211	77,372
CT	227,457	141,672	1,135,726	40,258	54,888	19,950	8,723
DE	43,663	60,334	272,156	64,538	22,750	9,593	13,831
DC	11,547	13,776	88,853	2,247	6,677	1,413	374
FL	1,057,563	854,854	6,187,403	358,630	480,078	182,486	74,743
GA	610,523	662,921	3,918,541	705,661	710,641	189,160	97,079
ID	190,024	113,066	740,115	23,895	350,773	75,032	66,486
IL	635,783	852,380	3,623,360	532,589	766,811	177,377	119,477
IN	427,319	737,729	2,839,774	1,030,000	708,782	180,063	107,426
IA	213,331	306,334	1,293,081	201,911	508,880	108,746	265,852
KS	245,172	373,217	1,985,198	134,594	754,989	194,411	176,915
KY	271,473	523,478	1,688,359	657,610	290,106	94,307	57,500
LA	368,095	641,334	1,964,164	310,972	278,198	103,516	82,713
ME	145,124	77,707	673,388	37,780	69,973	26,211	10,020
MD	259,411	297,677	1,791,761	312,887	135,275	58,223	30,461
MA	327,478	309,002	1,910,939	171,446	212,951	59,421	18,296
MI	625,791	694,018	3,947,679	518,658	474,494	118,916	75,450
MN	360,598	483,968	2,425,054	161,036	793,916	156,318	105,856
MS	303,449	320,326	1,235,467	149,527	381,809	84,567	75,157
MO	387,200	570,965	2,499,051	461,809	1,017,816	184,581	129,321
MT	66,059	157,484	513,397	40,131	359,256	68,188	47,486
NE	104,701	224,448	782,526	113,069	463,004	79,296	175,562
NV	79,723	142,108	640,957	91,731	122,108	25,790	7,911
NH	103,564	69,772	538,876	62,399	48,518	22,323	3,462
NJ	357,895	320,885	2,405,354	102,290	79,394	33,316	22,928
NM	140,773	265,149	1,425,745	81,245	867,554	151,792	41,353
NY	1,115,318	746,153	5,143,894	415,455	480,708	161,888	81,689
NC	596,122	598,232	3,703,327	611,112	349,679	131,063	169,322
ND	46,451	194,417	383,040	312,267	422,413	88,401	72,373
OH	618,872	1,013,324	4,289,927	1,346,258	578,024	185,592	126,375
OK	360,122	441,722	1,933,491	176,043	741,091	150,587	120,972
OR	504,330	286,322	1,601,864	35,310	535,678	244,181	58,772
PA	594,412	795,740	3,977,449	927,090	495,777	160,594	91,997
RI	35,378	35,642	280,800	6,941	9,575	3,259	1,149
SC	363,138	318,171	1,900,882	337,894	318,541	88,217	43,808
SD	54,523	89,332	446,779	27,187	292,537	63,285	103,246
TN	406,800	527,297	2,380,060	526,403	294,529	101,572	43,397
TX	1,472,014	1,874,221	7,823,308	1,048,675	2,474,105	441,474	412,972
UT	141,629	192,891	994,805	70,061	110,697	37,286	29,115
VT	42,088	31,613	318,543	7,340	57,332	12,159	9,746
VA	439,052	460,996	2,680,945	435,030	781,178	184,754	57,004
WA	334,379	356,980	2,155,526	86,482	290,160	86,812	50,304
WV	122,412	441,326	769,121	850,535	163,258	64,882	18,946
WI	446,489	412,221	2,251,225	263,436	323,522	89,603	127,333
WY	65,536	176,519	489,725	125,027	434,442	74,980	20,397
National	**17,798,117**	**20,837,195**	**107,690,881**	**15,318,580**	**21,143,074**	**5,489,280**	**3,982,852**

Table A-39. State Totals without CAAA Scenario – State Emissions Summary (tons per year)
Year = 2010

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	546,135	700,296	2,948,040	909,511	518,448	156,616	92,118
AZ	462,034	524,313	2,951,871	213,333	440,813	119,432	54,823
AR	299,525	313,900	1,522,261	181,657	300,022	96,467	152,170
CA	2,519,938	1,554,720	13,337,380	200,955	1,583,810	275,873	242,145
CO	445,799	442,754	2,700,574	232,119	557,249	125,117	75,825
CT	330,656	170,617	1,483,542	66,140	129,890	25,716	10,081
DE	87,270	97,177	400,301	103,199	41,561	13,290	15,839
DC	22,183	16,981	110,936	9,404	14,093	2,015	1,686
FL	1,299,043	1,082,553	7,324,706	830,342	851,332	191,420	97,748
GA	764,548	951,203	4,813,656	1,165,560	788,051	210,419	120,395
ID	145,109	109,882	853,640	60,286	158,512	70,693	76,914
IL	882,711	1,139,776	4,620,208	1,745,187	1,176,597	186,289	155,526
IN	680,365	1,130,691	3,408,647	2,219,889	812,300	192,662	122,417
IA	305,801	394,262	1,472,090	336,339	464,336	111,738	288,961
KS	362,939	463,964	2,109,600	161,505	1,259,529	194,113	129,880
KY	504,759	889,966	2,044,511	1,383,610	276,631	100,796	67,075
LA	560,275	838,059	2,744,024	650,402	466,154	114,062	153,043
ME	207,619	118,051	854,352	117,052	256,571	118,841	10,693
MD	420,284	446,684	2,507,194	495,025	258,460	71,918	35,200
MA	486,947	382,637	2,321,199	190,346	327,949	71,060	22,099
MI	1,035,506	948,240	4,622,521	772,250	627,233	126,522	85,487
MN	618,059	527,226	2,923,133	180,507	931,787	160,511	88,360
MS	397,984	373,113	1,372,020	266,555	288,516	81,559	104,381
MO	561,499	739,275	2,983,060	901,888	1,238,704	194,951	156,724
MT	110,742	194,676	639,268	82,169	336,061	63,159	47,479
NE	173,769	260,597	867,365	107,453	513,218	79,735	172,957
NV	137,547	189,620	949,744	96,351	176,231	34,728	8,875
NH	145,807	116,228	669,167	190,579	55,288	27,027	3,907
NJ	638,670	579,832	3,001,167	246,959	276,283	48,523	26,792
NM	190,322	375,566	1,574,835	184,352	1,327,555	129,128	48,794
NY	1,557,499	899,575	5,918,962	627,384	619,786	180,975	91,253
NC	910,008	964,184	4,331,325	856,369	461,880	158,609	186,284
ND	101,363	243,709	420,838	323,540	336,597	85,353	72,566
OH	963,794	1,423,627	5,538,665	3,174,203	731,503	202,065	130,990
OK	390,148	481,788	2,103,255	278,920	597,299	147,242	147,968
OR	552,622	365,451	2,120,409	93,316	594,082	264,218	59,569
PA	886,195	1,261,731	5,513,421	1,474,460	579,129	186,593	102,653
RI	71,667	39,722	360,862	12,077	29,020	4,316	1,872
SC	530,912	479,465	2,257,044	392,784	353,202	91,107	49,560
SD	88,031	106,699	507,079	67,258	268,020	61,406	102,223
TN	708,714	812,533	2,820,962	1,004,569	323,367	111,273	47,809
TX	2,083,824	2,398,988	9,652,267	1,281,152	2,927,815	445,936	425,036
UT	232,299	282,492	1,289,816	111,590	201,509	46,087	31,232
VT	65,108	46,426	352,469	17,703	56,014	14,902	8,972
VA	763,405	621,409	3,353,118	521,438	386,634	190,906	61,000
WA	556,071	418,853	3,007,385	147,058	491,304	95,989	53,872
WV	220,999	691,187	987,788	1,328,189	158,049	69,318	20,124
WI	623,643	619,704	2,937,692	600,041	508,010	107,253	122,701
WY	92,269	286,445	546,794	218,454	328,876	65,975	21,205
National	**26,742,416**	**28,516,847**	**134,151,164**	**26,831,429**	**26,405,279**	**5,923,897**	**4,405,282**

Table A-40. State Totals with CAAA Scenario – State Emissions Summary (tons per year)
Year = 2010

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	391,527	306,200	2,225,119	542,944	418,914	149,756	88,987
AZ	215,430	263,961	2,064,795	85,916	308,816	113,200	52,555
AR	217,362	196,152	1,153,960	134,934	289,418	92,955	139,211
CA	801,133	904,532	6,281,171	160,212	638,408	235,336	229,732
CO	297,445	246,371	1,963,847	187,674	320,100	111,841	73,226
CT	163,330	80,883	900,977	25,819	53,035	18,148	8,846
DE	31,974	35,960	235,671	65,730	24,382	10,038	14,906
DC	7,085	8,517	63,060	1,968	6,803	1,344	415
FL	868,812	536,012	5,537,261	295,705	488,990	180,543	81,803
GA	546,042	448,236	3,187,681	548,565	710,689	185,919	110,208
ID	215,191	96,104	690,572	22,618	324,144	75,495	79,392
IL	469,448	490,477	2,866,289	380,241	706,960	159,090	127,123
IN	351,069	385,619	2,202,595	483,494	663,867	157,079	114,705
IA	177,199	230,144	1,003,532	248,462	492,985	104,947	282,689
KS	211,185	319,734	1,728,605	133,127	741,908	187,487	183,764
KY	223,739	309,817	1,333,154	424,558	280,032	92,741	62,240
LA	335,626	547,680	1,624,138	286,575	280,110	105,394	92,719
ME	122,197	50,125	502,004	38,330	69,731	25,488	10,470
MD	187,177	148,691	1,537,669	136,669	123,158	45,647	32,677
MA	243,116	191,272	1,420,819	91,737	209,031	56,561	19,291
MI	481,187	461,461	3,082,366	509,614	462,941	113,814	78,980
MN	292,710	355,683	1,986,148	137,059	784,576	151,689	107,974
MS	246,461	230,542	909,765	139,453	339,840	77,889	82,672
MO	310,566	349,320	1,962,459	430,962	1,046,060	183,723	133,031
MT	57,612	140,507	449,896	36,373	327,225	64,319	48,569
NE	83,043	169,585	611,136	109,869	458,763	74,155	175,232
NV	60,999	121,260	602,751	46,862	129,723	27,218	8,700
NH	85,107	45,979	445,894	18,513	47,919	20,514	3,610
NJ	184,972	189,211	1,806,729	80,137	80,817	31,591	24,970
NM	119,980	230,761	1,256,612	67,745	765,618	142,280	47,700
NY	843,060	447,172	3,863,956	287,317	457,128	147,595	82,217
NC	504,972	338,392	3,037,941	340,585	351,313	126,900	183,930
ND	35,038	178,136	308,120	265,951	402,757	81,726	71,009
OH	475,809	474,157	3,263,680	410,669	517,045	136,182	133,028
OK	312,876	363,266	1,613,171	170,170	717,862	147,515	130,990
OR	505,885	234,597	1,558,708	30,748	506,237	253,228	62,557
PA	422,541	433,871	2,999,897	408,516	460,944	132,110	95,448
RI	24,822	19,635	213,469	6,536	9,459	2,982	1,310
SC	287,880	222,362	1,560,149	270,099	314,593	86,491	49,832
SD	43,284	69,678	365,090	25,976	280,018	58,843	103,226
TN	319,686	290,039	1,793,086	344,042	281,839	94,460	45,810
TX	1,255,172	1,364,547	6,801,811	793,765	2,455,300	436,099	433,069
UT	128,619	161,308	898,291	68,049	120,565	39,175	30,350
VT	33,283	18,472	229,357	7,172	56,960	12,259	8,717
VA	357,038	315,001	2,182,486	353,309	785,694	184,567	62,908
WA	281,414	275,669	1,874,380	56,651	270,076	85,472	52,825
WV	104,186	178,823	620,288	276,342	161,056	59,007	19,538
WI	376,822	254,659	1,887,690	237,771	313,760	89,140	120,194
WY	61,600	159,069	422,579	121,745	384,885	71,497	21,032
National	**14,372,711**	**13,889,649**	**87,130,822**	**10,347,277**	**20,442,451**	**5,241,449**	**4,224,388**

Table A-41. State Totals without CAAA Scenario – State Emissions Summary (tons per year)
Year = 2020

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	602,509	750,221	3,188,008	908,153	507,296	161,168	103,202
AZ	593,606	630,954	3,600,015	225,541	516,262	130,368	66,018
AR	359,652	367,002	1,775,385	289,077	322,026	103,922	171,711
CA	3,142,987	1,868,103	16,267,676	228,521	1,931,554	327,641	281,818
CO	557,472	512,739	3,198,004	240,283	664,158	144,142	80,948
CT	372,374	191,476	1,693,998	68,977	147,856	27,954	10,834
DE	103,382	110,198	479,279	112,672	48,138	14,914	18,537
DC	25,265	20,685	123,769	11,190	17,543	3,055	2,069
FL	1,579,446	1,271,729	8,903,560	864,795	966,912	209,428	109,831
GA	924,646	1,083,618	5,797,376	1,197,269	829,485	228,006	137,430
ID	178,647	131,276	1,028,330	74,933	193,684	81,812	91,166
IL	1,005,466	1,234,108	5,197,548	1,661,368	1,278,723	195,672	174,102
IN	780,212	1,191,496	3,804,001	2,073,260	865,243	196,131	136,277
IA	343,535	422,619	1,615,318	344,566	487,897	116,347	308,955
KS	404,002	497,447	2,273,175	169,339	1,295,311	199,385	134,262
KY	570,835	939,370	2,287,410	1,420,685	282,398	106,280	72,103
LA	660,868	1,045,185	3,193,211	1,127,122	532,692	128,638	177,411
ME	226,803	124,749	927,251	115,583	262,948	120,507	11,490
MD	499,265	521,837	2,976,189	520,346	311,596	87,955	39,360
MA	557,493	426,419	2,653,863	182,002	355,720	77,045	24,372
MI	1,183,517	1,045,109	5,234,820	820,084	686,172	137,404	91,524
MN	708,467	576,882	3,317,349	201,191	994,077	166,675	91,934
MS	444,504	399,189	1,455,312	259,989	263,544	85,822	112,758
MO	637,445	791,884	3,353,262	885,211	1,324,315	201,257	164,204
MT	130,483	218,642	742,938	93,597	330,382	67,801	49,227
NE	194,961	275,997	962,824	110,484	538,963	81,272	179,988
NV	176,862	226,872	1,232,697	100,596	216,862	43,096	9,898
NH	163,096	127,198	780,017	173,915	60,673	28,799	4,095
NJ	730,414	642,710	3,475,843	275,434	302,856	51,632	29,706
NM	227,122	427,297	1,795,908	211,432	1,236,903	136,485	53,787
NY	1,677,565	970,519	6,572,345	654,716	656,626	179,628	94,160
NC	1,098,538	1,075,493	5,215,703	879,841	522,312	173,296	211,377
ND	110,057	252,174	458,595	329,657	348,144	86,561	73,655
OH	1,088,060	1,508,655	6,083,954	3,186,475	790,472	211,456	142,050
OK	466,252	535,446	2,409,294	288,184	599,290	154,004	161,158
OR	632,910	424,003	2,595,127	95,792	610,952	289,334	62,623
PA	1,003,849	1,343,056	6,127,135	1,575,021	608,640	194,099	108,497
RI	84,293	44,992	417,053	12,784	32,707	4,618	2,167
SC	627,338	538,939	2,675,037	407,477	369,010	97,511	55,718
SD	97,096	112,465	553,935	68,129	279,966	62,799	104,915
TN	803,440	868,525	3,210,078	1,034,313	343,721	119,215	51,373
TX	2,499,747	2,703,803	11,676,070	1,374,928	3,027,759	486,831	451,519
UT	291,074	328,678	1,588,364	118,347	257,506	54,487	33,006
VT	74,870	51,475	406,077	18,302	59,280	15,884	8,138
VA	903,570	702,129	3,971,388	536,782	432,221	198,960	68,486
WA	673,289	495,573	3,659,508	163,480	579,689	110,206	57,022
WV	255,543	718,115	1,062,943	1,352,972	163,743	73,434	21,394
WI	708,226	681,904	3,340,848	620,407	545,449	124,086	118,072
WY	106,866	310,645	612,059	226,552	280,022	71,441	22,800
National	**31,287,920**	**31,739,600**	**155,969,849**	**27,911,774**	**28,279,698**	**6,368,466**	**4,787,148**

Table A-42. State Totals with CAAA Scenario – State Emissions Summary (tons per year)
Year = 2020

State	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
AL	379,859	241,418	2,148,318	364,973	378,574	143,653	99,859
AZ	212,352	190,295	2,139,328	86,662	334,187	117,964	63,315
AR	229,653	164,765	1,154,229	72,935	290,111	96,819	157,441
CA	790,352	695,810	6,012,602	163,214	655,454	245,313	269,877
CO	313,677	195,546	2,007,137	149,156	364,385	122,422	78,032
CT	149,950	49,655	850,847	25,774	54,478	17,089	9,297
DE	30,067	28,252	232,511	50,316	26,238	10,174	17,434
DC	6,029	5,308	56,334	2,079	7,754	1,482	441
FL	891,859	380,051	5,774,566	282,403	513,247	188,862	93,102
GA	575,558	290,566	3,201,280	270,841	710,354	184,529	128,175
ID	260,659	85,077	724,129	28,355	300,008	79,147	94,669
IL	456,984	368,229	2,638,515	385,337	736,254	161,446	140,342
IN	355,890	271,640	2,063,670	446,436	687,419	155,139	127,906
IA	170,456	180,175	928,519	240,082	513,192	106,527	302,849
KS	205,322	229,559	1,707,216	113,323	775,567	191,905	191,762
KY	210,728	224,502	1,251,859	288,829	274,060	87,832	66,963
LA	347,491	468,252	1,612,215	268,017	290,705	111,622	106,665
ME	104,608	32,754	478,329	31,466	71,146	24,386	11,210
MD	185,365	103,823	1,562,048	105,822	132,926	45,923	36,381
MA	227,166	129,778	1,361,762	90,599	215,967	55,463	20,741
MI	438,134	369,137	2,839,709	390,961	484,923	113,778	83,469
MN	250,076	292,330	1,843,818	126,199	820,988	154,676	112,200
MS	244,110	163,744	827,673	73,605	307,083	74,603	91,697
MO	298,603	275,880	1,850,255	448,943	1,104,805	189,584	139,355
MT	54,653	124,621	450,408	44,794	307,087	62,965	50,824
NE	77,207	131,169	569,735	73,011	479,621	75,949	182,406
NV	58,957	85,019	628,384	44,510	150,541	30,608	9,741
NH	74,650	33,876	438,599	18,133	50,159	20,325	3,734
NJ	156,804	126,807	1,719,910	65,559	81,602	29,637	27,371
NM	120,137	206,059	1,255,032	82,285	643,537	132,740	52,573
NY	753,300	308,821	3,698,895	228,744	438,147	130,911	82,394
NC	509,784	227,535	3,029,783	154,859	381,258	135,201	208,576
ND	28,954	128,650	279,932	238,024	412,689	81,730	72,084
OH	460,920	339,813	3,032,596	312,384	540,802	134,769	144,750
OK	296,279	290,642	1,606,168	101,322	700,292	150,243	141,843
OR	537,790	192,348	1,668,311	33,007	468,485	261,139	66,804
PA	403,307	317,236	2,815,712	274,399	457,366	121,844	100,438
RI	23,332	11,830	200,235	6,637	10,144	2,954	1,472
SC	296,835	165,191	1,567,448	197,325	317,173	91,615	56,199
SD	37,996	39,029	338,836	18,214	289,836	59,323	105,908
TN	303,035	198,652	1,677,979	178,550	285,336	92,738	48,891
TX	1,213,253	1,106,983	6,839,334	801,731	2,438,887	442,218	459,781
UT	131,076	124,915	912,144	53,325	144,500	43,480	32,018
VT	28,291	10,324	218,149	7,508	58,807	12,386	7,860
VA	353,776	260,271	2,162,403	289,847	795,257	188,835	71,925
WA	269,515	202,153	1,933,557	63,134	272,614	89,809	56,354
WV	104,662	139,953	636,428	171,321	160,942	55,224	20,903
WI	358,467	177,877	1,778,183	207,656	342,218	101,076	115,183
WY	62,405	117,229	414,513	99,533	324,051	68,594	22,959
National	**14,050,335**	**10,503,552**	**85,139,543**	**8,272,137**	**20,601,174**	**5,296,652**	**4,586,172**

APPENDIX B

IPM-CEM EMISSIONS COMPARISON

APPENDIX B | IPM-CEM EMISSIONS COMPARISON

To assess the accuracy of IPM's with-CAAA emissions estimates for 2001, the project team compared these estimates to 2001 continuous emission monitoring (CEM) data from EPA's Emission Tracking System (ETS). To conduct this analysis, the project team matched units included in IPM with the corresponding units in ETS based on their Office of Regulatory Information Systems (ORIS) identification number and boiler number. Of the 8,104 units in IPM, the project team identified matches in ETS for 1,918, slightly less than 25 percent. The estimated heat input of these 1,918 units, however, represents approximately 88 percent of the heat input modeled in IPM for the 2001 with-CAAA scenario.

Because the 2001 IPM run was constrained to reflect total emissions in 2001, IPM's 2001 with-CAAA emissions estimates for matching units are similar to the ETS emissions data. At the unit level, however, we found significant differences. Among matching units, we estimate a median difference of 430 tons between IPM's SO_2 emissions estimates and the estimates included in ETS. This represents approximately 28 percent of the SO_2 emissions generated among the median EGU. Similarly, we estimate that the median difference IPM and ETS estimates of NO_x emissions is 270 tons, or 28 percent of the NO_x emissions generated by the typical electric generating unit.

The magnitude of the unit-level statistics presented above suggests that the spatial distribution of emissions in IPM may be different than the actual distribution reflected in the ETS data. To examine the spatial distribution of emissions in IPM relative to the ETS data, we developed two estimates of total SO_2 and NO_x emissions for each state in 2001--one based on IPM's unit-level estimates and a second based on the 2001 ETS data. For each state (and pollutant), we then calculated the difference between IPM's estimates and the ETS data.

Exhibits B-1 through B-3 summarize the results of our comparative analysis. Exhibit B-1 suggests that IPM underestimates SO_2 emissions throughout most of the Southeast and Appalachia for 2001. In contrast, IPM’s SO_2 estimates exceed the corresponding ETS values for the West Coast and most of the Northeast. As indicated in Exhibit B-2, IPM exhibits a different pattern for NO_x emissions in 2001. Compared to the model’s estimation of SO_2 emissions, IPM is not as consistent in its overestimation or underestimation of NO_x emissions for the eastern half of the country. Similar to SO_2, however, Exhibit B-2 suggests that IPM underestimates NO_x emissions in Michigan, Ohio, and West Virginia—three states whose emissions significantly affect air quality in heavily populated areas in the Northeast. Throughout most of the Rockies and the Northern Plains the difference between the ETS data and IPM’s estimates suggests that IPM overestimates NO_x emissions in this region.

EXHIBIT B-1

COMPARISON OF IPM AND CEM ESTIMATES OF SO_2 EMISSIONS IN 2001 BY STATE

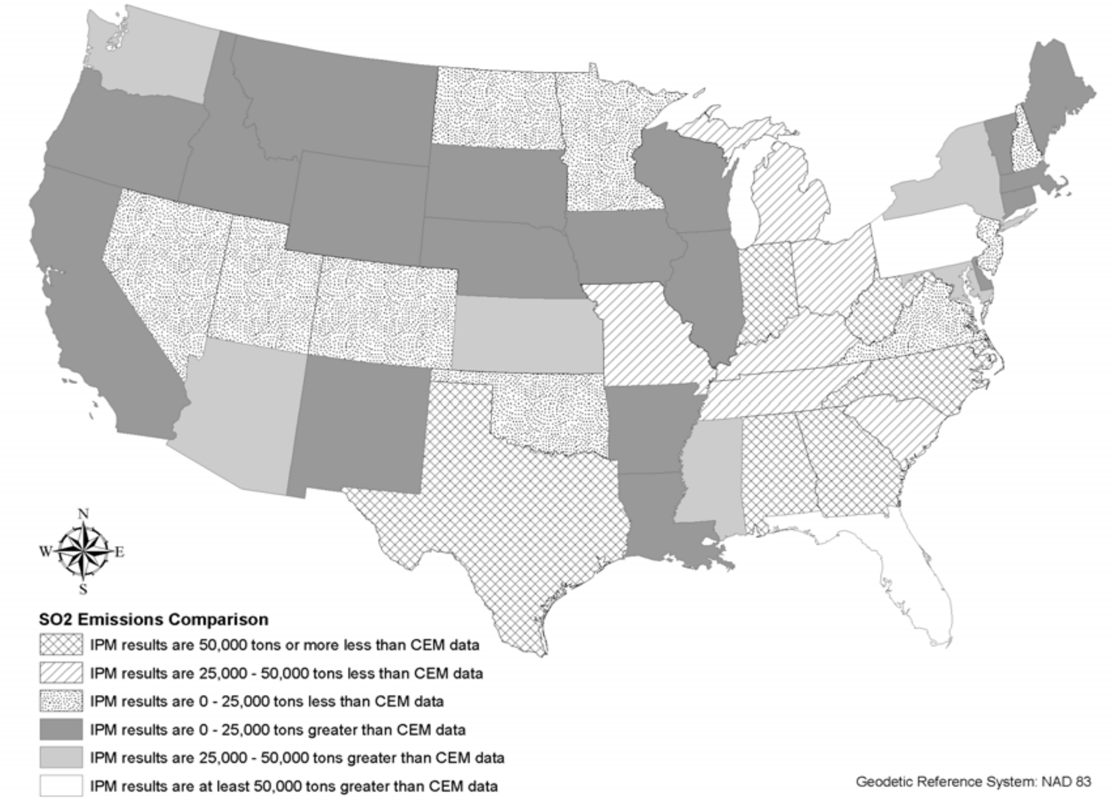


EXHIBIT B-2

COMPARISON OF IPM AND CEM ESTIMATES OF NO_x EMISSIONS IN 2001 BY STATE

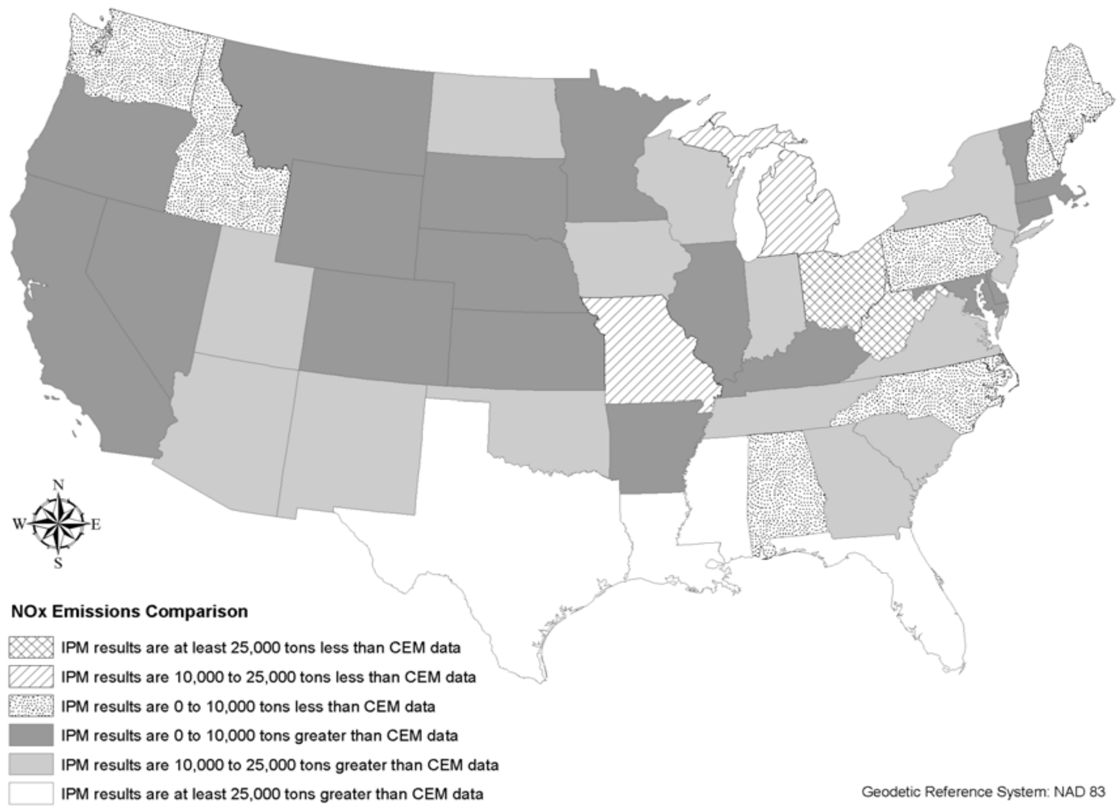


Exhibit B-3. Comparison Of Cem/Ets And Ipm Emissions Estimates For 2001

State	SO_2 Emissions: CEM/ETS (tons)	SO_2 Emissions: IPM (tons)	Difference between CEM/ETS and IPM SO_2 Emissions (tons)*	NO_x Emissions: CEM/ETS (tons)	NO_xEmissions : IPM (tons)	Difference between CEM/ETS and IPM NO_x Emissions (tons)*
Alabama	465,846	559,925	-94,079	166,608	166,809	-201
Arizona	73,325	47,637	25,688	93,019	74,008	19,011
Arkansas	78,199	77,159	1,040	47,192	40,317	6,876
California	1,868	0	1,868	18,429	14,520	3,909
Colorado	88,595	108,683	-20,088	68,836	65,313	3,523
Connecticut	34,121	15,227	18,894	10,855	4,585	6,270
Delaware	34,879	13,531	21,348	10,502	9,743	759
Dist. of Columbia	754	0	754	235	0	235
Florida	462,201	188,230	273,970	238,324	170,522	67,802
Georgia	485,843	573,170	-87,326	160,742	149,563	11,179
Idaho	3	0	3	157	412	-255
Illinois	368,039	358,126	9,913	199,341	192,932	6,409
Indiana	731,531	828,617	-97,086	299,977	283,214	16,763
Iowa	133,540	111,763	21,777	78,469	62,657	15,813
Kansas	120,001	77,691	42,310	84,477	82,132	2,345
Kentucky	535,444	567,004	-31,559	231,729	222,523	9,206
Louisiana	112,798	97,429	15,369	80,459	44,257	36,201
Maine	6,797	0	6,797	1,610	2,844	-1,234
Maryland	250,205	224,518	25,687	70,119	65,446	4,672
Massachusetts	102,906	91,182	11,723	30,630	28,127	2,503
Michigan	347,058	381,364	-34,306	141,117	153,474	-12,357
Minnesota	91,536	97,075	-5,539	80,293	77,717	2,576
Mississippi	138,344	91,061	47,283	57,234	30,153	27,080
Missouri	231,561	279,465	-47,904	144,715	165,922	-21,207
Montana	24,403	17,824	6,578	39,435	35,476	3,959
Nebraska	70,250	68,290	1,960	47,883	45,317	2,565
Nevada	54,694	73,684	-18,990	43,549	41,293	2,256
New Hampshire	48,127	50,452	-2,325	6,796	7,139	-343
New Jersey	50,209	60,014	-9,805	25,903	12,399	13,504
New Mexico	62,191	51,782	10,409	83,080	72,085	10,995
New York	248,912	204,685	44,226	73,839	61,795	12,044
North Carolina	448,948	510,868	-61,920	143,363	153,186	-9,823
North Dakota	154,934	164,566	-9,632	79,114	59,721	19,393
Ohio	1,114,751	1,150,358	-35,608	330,459	395,423	-64,964
Oklahoma	101,436	121,139	-19,703	83,154	73,115	10,038
Oregon	17,824	9,857	7,967	10,846	7,573	3,272
Pennsylvania	931,149	712,849	218,300	200,277	202,136	-1,859
South Carolina	196,030	241,161	-45,130	79,923	57,179	22,744
South Dakota	13,618	9,563	4,055	16,489	12,934	3,554
Tennessee	356,587	392,933	-36,346	154,737	142,495	12,242
Texas	541,335	629,959	-88,625	303,245	207,001	96,244
Utah	28,321	48,306	-19,985	71,510	57,889	13,621
Vermont	5	0	5	229	0	229
Virginia	200,215	215,892	-15,677	73,457	63,089	10,368
Washington	66,910	29,837	37,073	18,330	22,915	-4,585
West Virginia	497,336	767,775	-270,439	203,319	279,523	-76,205
Wisconsin	175,395	174,019	1,376	98,471	86,149	12,322
Wyoming	84,467	80,612	3,855	84,251	78,435	5,816

* Positive values indicate that the CEM/ETS emissions values are greater than IPM's emissions estimates.

Exhibits B-1 and B-2 clearly demonstrate that IPM's spatial distribution of with-CAAA emissions in 2001 is different than the actual distribution of emissions. Although this represents a limitation of IPM, we believe it is appropriate to use IPM's with-CAAA emissions estimates for 2001 rather than the ETS data. Because the purpose of the Second Prospective is to compare the with-CAAA scenario to the without-CAAA counterfactual, it is important that the methodology for measuring emissions and the spatial distribution of emissions is consistent across the two scenarios. While the IPM estimates for the with-CAAA and without-CAAA scenarios are methodologically consistent, it is not possible to develop without-CAAA emissions estimates consistent with the ETS data. Therefore, we do not think it would be appropriate to use the ETS data for the primary emissions estimates for the Second Prospective. Instead, it may be more appropriate to use these data for a sensitivity analysis.

APPENDIX C

OTHER IPM RESULTS

APPENDIX C | OTHER IPM RESULTS

As indicated above, to estimate utility emissions under the with-CAAA and without-CAAA scenarios, IPM simulates the operation of the utility sector in significant detail. Therefore, the model generates a number of outputs in addition to emissions. Exhibit C-1 summarizes IPM's estimates of generating capacity by fuel type under the with-CAAA and without-CAAA scenarios for the years 2001, 2010, and 2020. For 2001, the mix of generating capacity is the same under both scenarios because the project team constrained the model to reflect the generating capacity that was in place in 2001. The results for 2010 and 2020 suggest that coal-fired capacity would be higher if the Amendments had not been enacted and that the Amendments have had a positive impact on natural gas and renewables capacity.

Exhibit C-1. Summary Of Ipm Capacity Estimates By Fuel Type (Mw)

Fuel Type	2001 without-CAAA	2001 with-CAAA	2010 without-CAAA	2010 with-CAAA	2020 without-CAAA	2020 with-CAAA
Coal	303,103	303,104	302,530	299,579	316,300	307,910
Hydro	109,292	109,291	109,643	109,643	109,643	109,643
Nuclear	99,036	99,036	100,819	100,819	102,862	102,862
Oil/Natural Gas	294,084	294,082	398,904	398,755	504,214	512,126
Other	9,337	9,337	10,448	10,448	10,448	10,448
Renewables	8,297	8,297	13,622	13,636	14,366	14,485
TOTAL	823,149	823,147	935,966	932,880	1,057,833	1,057,474

Similar to capacity, the composition of generation under the with-CAAA scenario is different than that under the without-CAAA scenario. Unlike capacity, however, the fuel mix for generation differs for all three target years rather than just for 2010 and 2020. Although IPM was constrained to hold capacity constant under both regulatory scenarios for 2001, the model was free to simulate 2001 dispatch subject to the constraints included in each scenario. Therefore, as indicated in Exhibit C-2, IPM estimates that coal-based and hydroelectric generation in 2001 are higher under the without-CAAA scenario than under the with-CAAA scenario, while generation by natural gas/oil is greater under the with-CAAA scenario. The model produced similar results for 2010 and 2020.

Exhibit C-2. Summary Of Ipm Generation Estimates (GWh)

Fuel Type	2001 without-CAAA	2001 with-CAAA	2010 without-CAAA	2010 with-CAAA	2020 without-CAAA	2020 with-CAAA
Coal	2,027,224	2,022,124	2,217,517	2,181,797	2,348,733	2,268,011
Hydro	229,240	224,937	296,040	290,156	291,754	288,350
Nuclear	759,472	759,472	796,479	796,479	808,378	808,379
Oil/Natural Gas	535,343	538,704	883,598	916,801	1,414,317	1,492,428
Other	48,205	48,205	44,780	44,737	50,023	50,023
Renewables	39,664	40,040	58,364	58,865	62,297	63,241
TOTAL	3,639,148	3,633,483	4,296,778	4,288,835	4,975,502	4,970,432

In addition to capacity and generation by fuel type, IPM also estimates energy prices and allowance prices for each target year, as summarized in Exhibit C-3. As indicated by these results, IPM estimates that the Amendments have increased electricity prices relative to prices under the without-CAAA scenario. Because the Amendments have increased the cost of producing electricity, the project team expected this result. For 2010 and 2020, IPM's results also suggest that natural gas prices are higher under the with-CAAA scenario than under the without-CAAA scenario. This is consistent with the utility sector's higher demand for natural gas under the with-CAAA scenario relative to the without-CAAA scenario as indicated in Exhibit C-2. In contrast to natural gas, IPM estimates that coal prices are lower under the with-CAAA scenario in 2001 and 2010 than under the without-CAAA scenario. This likely reflects the shift away from coal-based generation projected to occur under the Amendments, as shown above in Exhibit C-2. For 2020, however, IPM estimates that coal prices are higher under the with-CAAA scenario than under the without-CAAA scenario. This reflects differences in the types of coal purchased by utilities between the with-CAAA and without-CAAA scenarios.

Exhibit C-3 indicates that allowance prices for NO_x fall significantly between 2001 and 2010. This reduction reflects the differences between the regulation of NO_x in 2001 and 2010. The 2001 estimate reflects the Ozone Transport Commission (OTC) summer program for NO_x, whereas later estimates reflect NO_x SIP Call and the Clean Air Interstate Rule (CAIR). While the OTC program only affected a small group of states in the Northeast, NO_x SIP Call and CAIR affect several states in the Midwest (in addition to the Northeast), where coal-based generation is more prevalent relative to the Northeast. Because the marginal cost of controlling NO_x is relatively low for coal-fired plants, the allowance price under NO_x SIP Call and CAIR in 2010 is lower than that associated with the OTC summer program in 2001. In addition, unlike the OTC summer program, CAIR sets an annual cap on NO_x emissions rather than a seasonal cap. Under the OTC program, the cost of implementing NO_x controls is spread over the emissions reductions achieved in the summer, while the cost of controlling NO_x emissions under CAIR is spread over the reductions achieved during the entire year. Therefore, the cost per ton of NO_x controlled (and the allowance price) is lower under CAIR in 2010 than under the OTC program in 2001.

Exhibit C-3. IPM Estimates Of Energy And Allowance Prices

IPM Output	2001 without-CAAA	2001 with-CAAA	2010 without-CAAA	2010 with-CAAA	2020 without-CAAA	2020 with-CAAA
Minemouth Coal Prices ($/MMBtu)	$0.71	$0.68	$0.69	$0.66	$0.65	$0.66
Henry Hub Natural Gas Prices ($/MMBtu)	$2.75	$2.75	$3.40	$3.45	$3.45	$3.54
Wholesale electricity prices ($/MWh)	$24.80	$26.21	$29.64	$30.96	$35.93	$36.77
SO_2 Allowance Price ($ per allowance)	Not Applicable	$361	Not Applicable	$412	Not Applicable	$397
NO_x Allowance Price ($ per allowance)	Not Applicable	$2,490	Not Applicable	$1,184	Not Applicable	$1,394
Hg Allowance Price ($ per pound)	Not Applicable	Not Applicable	Not Applicable	$25,170	Not Applicable	$42,340
All estimates are presented in year 1999 dollars.						

Exhibit C-4 compares 2001 fuel and allowance prices as estimated by IPM for the with-CAAA scenario to actual prices observed in 2001.[7] As indicated by Exhibit C-4, IPM's coal price estimate is similar to the average coal price observed in 2001, but the model overestimates allowance prices for both SO_2 and NO_x and underestimates the price of natural gas. The inconsistencies between IPM's natural gas and allowance prices and actual prices observed on the open market may affect IPM's modeling of electric utilities' investment and dispatch decisions. However, because the 2001 with-CAAA model run was constrained to reflect actual emissions in 2001, these inconsistencies may affect the spatial distribution of emissions across the U.S., but not aggregate emissions.[8] As indicated in Appendix B, the actual distribution of SO_2 and NO_x emissions across different states in 2001 was different than the distribution estimated by IPM for the 2001 with-CAAA scenario. Despite this difference, we believe it is appropriate to use the IPM with-CAAA emissions estimates for 2001 rather than the emissions data collected by EPA. To make a valid comparison between with-CAAA and without-CAAA emissions for the Second Prospective, it is important that the project team use a consistent methodology for both scenarios. Therefore, in the absence of counterfactual emissions data for the without-CAAA scenario, it is more appropriate to conduct a model-to-model comparison of IPM results for both scenarios instead of comparing 2001 emissions data to IPM's results for the without-CAAA scenario.

[7] Although Exhibit C-3 presents minemouth and Henry Hub prices for coal and natural gas, respectively, we present delivered prices in Exhibit C-4 because data for the delivered price of each fuel was more readily available than minemouth and Henry Hub data.

[8] In addition, sensitivity analyses conducted internally by EPA suggest that IPM's aggregate results are not highly sensitive to changes in natural gas prices. U.S. EPA, "Multi-pollutant Analysis: Natural Gas Price Sensitivity," April 2006, http://www.epa.gov/airmarkets/mp/.

Exhibit C-4. Comparison Of IPM Price Estimates For 2001 And Actual 2001 Prices*

Price Description	IPM Estimate: with-CAAA scenario for 2001	Observed Values for 2001
Coal Delivered to Utilities ($/MMBtu)	$1.22	$1.17[1]
Natural Gas Delivered to Utilities ($/MMBtu)	$2.93	$4.46[2]
SO_2 Allowance Price ($ per allowance)	$361	$172[3]
NO_x Allowance Price ($ per allowance)	$2,490	$860-$1,433[4]

* All values are presented in year 1999 dollars.
Sources:

1. U.S. Department of Energy, Energy Information Administration, *Annual Coal Report 2002*.
2. U.S. Department of Energy, Energy Information Administration, "Natural Gas Monthly May 2005."
3. Sales weighted average of monthly average prices reported by Cantor Fitzgerald.
4. Cantor Environmental Brokerage, "NO_x Budget Allowance MPI History" and Natsource, "Full OTC Nox Price History - Mid Market Prices."

APPENDIX D

OFFROAD AND NONROAD COMPARISON FOR CALIFORNIA

APPENDIX D | OFFROAD AND NONROAD COMPARISON FOR CALIFORNIA

INTRODUCTION

This appendix provides additional detail on our comparison of emissions estimates from the State of California's OFFROAD model to the USEPA NONROAD model estimates for California. The Air Resources Board (ARB) has developed their own model for preparing nonroad emission inventories named OFFROAD. There is a separate model for California, in part, because California sets its own off-road equipment emission standards. For the second Section 812 Prospective, the United States Environmental Protection Agency (EPA) requested that the ARB provide OFFROAD-based inventories for both with and without Clean Air Act Amendments (CAAA) scenarios for the years of interest. However, only controlled inventories were readily available from ARB. Because OFFROAD-based emissions reflecting a without-CAAA scenario were not available, EPA NONROAD model-based emissions for California were used in the Section 812 Prospective analysis.

Past comparisons have shown that the estimates from OFFROAD for some equipment types differ significantly from NONROAD estimates, especially for volatile organic compounds (VOC) and carbon monoxide (CO). To examine the existing difference between these two nonroad emission models, results obtained from the with-CAAA NONROAD model runs for California were compared with Statewide nonroad controlled inventories (i.e., with CAAA) based on ARB's OFFROAD model. As described in Chapter 5 of this report, the Project Team compiled OFFROAD-based emission estimates for VOC, oxides of nitrogen (NO_x), CO, particulate matter less than or equal to 2.5 micrometers ($PM_{2.5}$), and sulfur dioxide (SO_2) for the years 1990, 2000, 2010, and 2020. Controlled emissions inventories for California were obtained from ARB's *Emission Inventory Data - Almanac Emission Projection Data* (ARB, 2005a).

This appendix supplements the Chapter 5 summary of this analysis with further evaluation of the results to determine what factors are causing some of the significant differences. This analysis first examines overall nonroad sector inventories, as well as the effect of categories being absent from the OFFROAD-based inventories (e.g., liquefied petroleum gasoline fueled engines). It then focuses on a subset of categories that show the most significant discrepancies, compares equipment populations, and also investigates the impact of California standards on emissions (i.e., relative to Federal standards).

In summary, discrepancies are shown to result in part from differences in equipment activity, category-specific future emission standards, and variations in fuel input data (e.g., fuel sulfur content). Some of the differences are substantial when comparing all categories combined for a given pollutant. However, one large discrepancy for the gasoline lawn and garden category is attributable to outdated data on equipment populations. When updated with new survey data from California, the difference is expected to narrow substantially. In addition, more stringent State-level fuel sulfur requirements in California than the rest of the U.S. explain the differences observed in SO_2 emission estimates. California's information on the sulfur content of off-road diesel fuel appears to be more accurate than what is in EPA's NONROAD model defaults for historical years.

OFFROAD COMPARISONS

Exhibit D-1 shows a comparison by year for total NONROAD model category emissions. ARB estimates total VOC emissions for each *with-CAAA* scenario year to be approximately 30 to 40 percent lower than EPA, and estimates CO emissions to be 50 to 75 percent lower than EPA. ARB also estimates $PM_{2.5}$ emissions to be about 10 percent lower than EPA on average for all years except 1990, which shows slightly higher $PM_{2.5}$ emissions. ARB's NO_x estimates are considerably higher in 1990 (+98 percent), and in 2000 (+45 percent), but are only about 20 percent higher than EPA for the years 2010 and 2020. Finally, ARB estimates SO_2 emissions to be 55 percent higher than EPA in 1990, and 163 percent higher in 2020. Overall, SO_2 emissions in 2000 and 2010 are much lower based on ARB's model (-93 percent and –52 percent, respectively).

Exhibit D-1. EPA and ARB Overall Nonroad Emissions Comparison - State of California

Year	Pollutant	EPA	ARB	Absolute Difference	Percent Difference
1990	VOC	270,139	191,156	-78,983	-29%
2000	VOC	237,704	171,592	-66,112	-28%
2010	VOC	158,493	104,727	-53,766	-34%
2020	VOC	142,339	84,345	-57,994	-41%
1990	NOX	164,566	325,389	160,823	98%
2000	NOX	173,505	251,607	78,102	45%
2010	NOX	146,092	177,877	31,785	22%
2020	NOX	98,241	116,505	18,264	19%
1990	CO	2,615,018	1,339,546	-1,275,472	-49%
2000	CO	2,545,659	1,105,559	-1,440,100	-57%
2010	CO	3,141,091	908,788	-2,232,303	-71%
2020	CO	3,696,579	923,533	-2,773,046	-75%
1990	PM25	21,101	22,118	1,016	5%
2000	PM25	18,692	16,738	-1,954	-10%
2010	PM25	16,240	14,287	-1,953	-12%
2020	PM25	12,142	11,254	-888	-7%
1990	SO2	13,095	20,291	7,196	55%
2000	SO2	13,849	942	-12,906	-93%
2010	SO2	1,483	715	-768	-52%
2020	SO2	296	776	481	163%

ENGINE CATEGORY COMPARISON

Exhibit D-2 compares EPA and ARB results for 2000 at an engine (i.e., fuel) category level. For all pollutants, total gasoline emissions from ARB are lower than EPA, and total diesel emissions per ARB are higher than EPA estimates. The impact these engine specific differences have on the total inventory depend on the relative contribution of the general engine category for each pollutant inventory. For example, decreases in gasoline VOC outweigh the increases in diesel VOC emissions because the gasoline engines contribute significantly more to the VOC emissions inventory than the diesel, compressed natural gas (CNG) or liquefied petroleum gas (LPG) engines. In addition, one general engine category that is absent from ARB's OFFROAD model is LPG engines. Because this category is not a significant contributor for most pollutants (with the exception of NO_x), the exclusion of this category from OFFROAD results in minimal differences.

Exhibit D-2. EPA and ARB 2000 Year Engine-Level Emissions Comparison

Pollutant	Engine	EPA	ARB	Absolute Difference	Percent Difference
VOC	Gasoline	215,402	144,220	-71,182	-33%
VOC	Diesel	15,495	27,361	11,866	77%
VOC	CNG/LPG	6,807	11	-6,795	-100%
NOX	Gasoline	25,680	24,375	-1,305	-5%
NOX	Diesel	119,446	214,874	95,428	80%
NOX	CNG/LPG	28,379	12,358	-16,021	-56%
CO	Gasoline	2,363,666	979,198	-1,384,468	-59%
CO	Diesel	70,265	97,464	27,199	39%
CO	CNG/LPG	111,728	28,898	-82,830	-74%
PM25	Gasoline	6,630	3,512	-3,118	-47%
PM25	Diesel	11,930	13,160	1,231	10%
PM25	CNG/LPG	133	66	-67	-51%
SO2	Gasoline	1,156	479	-677	-59%
SO2	Diesel	12,662	457	-12,205	-96%
SO2	CNG/LPG	30	6	-24	-80%

EQUIPMENT CATEGORY COMPARISON

With some exceptions, the data reported by ARB corresponds to general equipment categories, or 7-digit EPA source classification codes (SCCs). Seven-digit SCCs are roughly equivalent to Tier 3 categories. The results of comparisons at a Tier 3 source category level are shown in Exhibits D-3 through D-7 for VOC, NO_x, CO, $PM_{2.5}$, and SO_2, respectively. Appendix A includes a correspondence table that shows the specific equipment categories reported by ARB and how they were matched to EPA Tier categories.

EPA's inclusion of three other equipment categories not covered by ARB's inventory, including gasoline and diesel railway maintenance and diesel recreational vehicles, have a small impact on total mass emissions, and as such are not contributing significantly to any observed differences.

Exhibit D-3. Comparison of EPA Section 812 and ARB VOC Emissions for California, tpy

		1990			2000			2010			2020		
TIER 2 NAME	**TIER 3 NAME**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**
Non-Road Gasoline	recreational	15,142	22,241	47%	19,483	20,605	6%	34,635	21,391	-38%	17,870	24,626	38%
	construction	8,250	2,122	-74%	4,680	1,477	-68%	2,264	976	-57%	2,438	959	-61%
	industrial	7,098	3,050	-57%	2,052	2,815	37%	548	1,140	108%	180	759	322%
	lawn & garden	144,780	78,822	-46%	114,804	57,234	-50%	60,821	29,149	-52%	70,039	26,864	-62%
	farm	327	1,170	258%	295	982	233%	189	833	341%	163	688	322%
	light commercial	27,281	8,843	-68%	18,971	6,870	-64%	11,839	4,483	-62%	14,870	3,563	-76%
	logging	569	2,417	325%	517	1,163	125%	332	538	62%	434	538	24%
	airport service	55	208	278%	34	253	647%	12	98	728%	10	69	585%
	railway maintenance	37	NA	NA	20	NA	NA	12	NA	NA	14	NA	NA
	recreational marine vessels	44,212	37,822	-14%	54,546	52,821	-3%	33,368	28,580	-14%	27,583	16,755	-39%
	Subtotal: Non-Road Gasoline	**247,752**	**156,695**	**-37%**	**215,402**	**144,220**	**-33%**	**144,019**	**87,187**	**-39%**	**133,600**	**74,821**	**-44%**
Non-Road Diesel	recreational	49	NA	NA	56	NA	NA	56	NA	NA	44	NA	NA
	construction	10,591	17,968	70%	8,939	14,043	57%	7,035	8,487	21%	4,819	5,071	5%
	industrial	2,025	3,885	92%	1,707	3,408	100%	1,032	2,499	142%	705	1,227	74%
	lawn & garden	715	477	-33%	872	334	-62%	698	183	-74%	531	3	-99%
	farm	2,068	8,959	333%	1,831	7,250	296%	1,115	4,590	312%	706	2,136	202%
	light commercial	1,481	1,773	20%	1,688	1,531	-9%	1,472	1,153	-22%	988	536	-46%
	logging	162	1,059	552%	87	427	388%	40	222	456%	21	137	558%
	airport service	157	137	-13%	135	137	1%	97	122	26%	70	81	17%
	railway maintenance	70	NA	NA	76	NA	NA	68	NA	NA	44	NA	NA
	recreational marine vessels	84	194	132%	105	232	121%	125	276	122%	124	328	164%
	Subtotal: Non-Road Diesel	**17,402**	**34,451**	**98%**	**15,495**	**27,361**	**77%**	**11,738**	**17,533**	**49%**	**8,051**	**9,520**	**18%**
Other	liquified petroleum gas	4,946	NA	NA	6,757	NA	NA	2,722	NA	NA	682	NA	NA
	compressed natural gas	40	10	-75%	50	11	-77%	14	6	-60%	6	4	-30%
	Subtotal: Other Sources	**4,986**	**10**	**-100%**	**6,807**	**11**	**-100%**	**2,736**	**6**	**-100%**	**688**	**4**	**-99%**
TOTAL: ALL SOURCES		**270,139**	**191,156**	**-29%**	**237,704**	**171,592**	**-28%**	**158,493**	**104,727**	**-34%**	**142,339**	**84,345**	**-41%**

Exhibit D-4. Comparison of EPA Section 812 and ARB NO_x Emissions for California, tpy

		1990			2000			2010			2020		
TIER 2 NAME	**TIER 3 NAME**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**
Non-Road Gasoline	recreational	457	1,191	161%	803	1,524	90%	1,115	1,792	61%	1,290	2,058	60%
	construction	437	1,096	151%	679	754	11%	464	889	91%	419	915	119%
	industrial	2,685	7,029	162%	1,686	7,265	331%	494	3,075	522%	93	2,328	2393%
	lawn & garden	6,436	2,073	-68%	14,710	2,524	-83%	11,158	3,030	-73%	12,902	2,558	-80%
	farm	82	1,201	1367%	137	821	499%	101	849	744%	84	918	994%
	light commercial	1,760	2,977	69%	4,655	2,951	-37%	4,154	3,237	-22%	4,949	3,335	-33%
	logging	10	97	910%	20	43	111%	24	61	155%	30	61	103%
	airport service	23	904	3895%	32	1,225	3775%	11	451	4158%	6	308	4923%
	railway maintenance	3	NA	NA	8	NA	NA	5	NA	NA	6	NA	NA
	recreational marine vessels	2,154	5,568	158%	2,949	7,268	146%	4,536	11,227	148%	5,678	9,452	66%
	Subtotal: Non-Road Gasoline	**14,045**	**22,135**	**58%**	**25,680**	**24,375**	**-5%**	**22,062**	**24,610**	**12%**	**25,456**	**21,934**	**-14%**
Non-Road Diesel	recreational	124	NA	NA	151	NA	NA	176	NA	NA	172	NA	NA
	construction	84,582	164,039	94%	71,672	121,026	69%	65,865	83,714	27%	34,626	51,937	50%
	industrial	15,115	27,362	81%	14,062	21,340	52%	11,969	15,774	32%	7,087	9,476	34%
	lawn & garden	3,799	2,260	-41%	5,135	2,452	-52%	6,169	531	-91%	5,674	8	-100%
	farm	12,618	72,901	478%	14,002	53,602	283%	11,969	35,101	193%	7,397	20,392	176%
	light commercial	7,069	12,864	82%	8,763	9,944	13%	9,913	7,680	-23%	8,237	4,860	-41%
	logging	2,150	10,448	386%	1,083	4,067	276%	527	2,376	351%	77	1,305	1586%
	airport service	1,611	1,601	-1%	1,479	1,478	0%	1,337	1,246	-7%	565	764	35%
	railway maintenance	323	NA	NA	370	NA	NA	379	NA	NA	268	NA	NA
	recreational marine vessels	2,168	856	-61%	2,729	965	-65%	3,410	1,149	-66%	3,700	1,368	-63%
	Subtotal: Non-Road Diesel	**129,560**	**292,330**	**126%**	**119,446**	**214,874**	**80%**	**111,714**	**147,571**	**32%**	**67,804**	**90,111**	**33%**
Other	liquified petroleum gas	18,477	NA	NA	25,270	NA	NA	11,222	NA	NA	4,393	NA	NA
	compressed natural gas	2,485	10,924	340%	3,110	12,358	297%	1,094	5,695	420%	589	4,460	657%
	Subtotal: Other Sources	20,961	10,924	-48%	28,379	12,358	-56%	12,316	5,695	-54%	4,982	4,460	-10%
TOTAL: ALL SOURCES		**164,566**	**325,389**	**98%**	**173,505**	**251,607**	**45%**	**146,092**	**177,877**	**22%**	**98,241**	**116,505**	**19%**

Exhibit D-5. Comparison of EPA Section 812 and ARB CO Emissions for California, tpy

		1990			2000			2010			2020		
TIER 2 NAME	**TIER 3 NAME**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**
Non-Road Gasoline	recreational	98,688	106,244	8%	96,366	93,541	-3%	160,473	102,822	-36%	176,602	118,302	-33%
	construction	83,783	47,537	-43%	58,626	35,089	-40%	67,656	29,119	-57%	74,778	29,444	-61%
	industrial	121,507	59,249	-51%	54,906	50,429	-8%	30,699	48,266	57%	14,165	49,710	251%
	lawn & garden	1,589,716	510,820	-68%	1,549,253	362,430	-77%	1,934,951	243,456	-87%	2,363,369	266,472	-89%
	farm	6,504	31,424	383%	7,516	25,200	235%	8,052	22,991	186%	9,028	22,143	145%
	light commercial	433,437	190,600	-56%	460,887	151,119	-67%	658,655	129,187	-80%	855,475	120,297	-86%
	logging	3,608	16,740	364%	3,245	6,377	97%	4,235	4,326	2%	5,800	4,326	-25%
	airport service	874	3,511	302%	821	3,911	376%	648	3,123	382%	640	3,151	392%
	railway maintenance	781	NA	NA	728	NA	NA	886	NA	NA	1,006	NA	NA
	recreational marine vessels	117,353	205,463	75%	131,318	251,101	91%	134,459	219,049	63%	138,933	206,876	49%
	Subtotal: Non-Road Gasoline	**2,456,252**	**1,171,588**	**-52%**	**2,363,666**	**979,198**	**-59%**	**3,000,713**	**802,338**	**-73%**	**3,639,795**	**820,722**	**-77%**
Non-Road Diesel	recreational	192	NA	NA	217	NA	NA	225	NA	NA	184	NA	NA
	construction	49,164	81,941	67%	43,465	51,731	19%	36,640	40,544	11%	18,755	38,528	105%
	industrial	7,798	14,906	91%	6,911	11,904	72%	6,468	9,354	45%	1,879	8,031	327%
	lawn & garden	2,521	1,432	-43%	3,039	1,532	-50%	2,944	220	-93%	2,300	12	-99%
	farm	8,538	32,084	276%	8,487	24,555	189%	5,835	17,666	203%	3,166	14,864	370%
	light commercial	5,565	6,235	12%	6,198	5,103	-18%	6,207	4,261	-31%	4,341	3,676	-15%
	logging	998	4,465	347%	457	1,542	238%	221	1,184	436%	31	1,161	3654%
	airport service	672	748	11%	722	670	-7%	599	642	7%	249	647	160%
	railway maintenance	310	NA	NA	331	NA	NA	295	NA	NA	180	NA	NA
	recreational marine vessels	350	356	2%	439	426	-3%	582	507	-13%	731	603	-17%
	Subtotal: Non-Road Diesel	**76,108**	**142,167**	**87%**	**70,265**	**97,464**	**39%**	**60,016**	**74,377**	**24%**	**31,817**	**67,522**	**112%**
Other	liquified petroleum gas	72,734	NA	NA	99,332	NA	NA	74,064	NA	NA	22,254	NA	NA
	compressed natural gas	9,924	25,791	160%	12,396	28,898	133%	6,298	32,073	409%	2,712	35,289	1201%
	Subtotal: Other Sources	82,659	25,791	-69%	111,728	28,898	-74%	80,362	32,073	-60%	24,967	35,289	41%
TOTAL: ALL SOURCES		**2,615,018**	**1,339,546**	**-49%**	**2,545,659**	**1,105,559**	**-57%**	**3,141,091**	**908,788**	**-71%**	**3,696,579**	**923,533**	**-75%**

Exhibit D-6. Comparison of EPA Section 812 and ARB $PM_{2.5}$ Emissions for California, tpy

		1990			2000			2010			2020		
TIER 2 NAME	**TIER 3 NAME**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**
Non-Road Gasoline	recreational	401	66	-83%	577	77	-87%	1,104	89	-92%	551	102	-82%
	construction	218	19	-91%	183	176	-4%	204	226	11%	230	237	3%
	industrial	72	26	-64%	19	32	62%	9	36	290%	4	38	966%
	lawn & garden	2,762	1,151	-58%	3,065	1,051	-66%	3,389	706	-79%	4,099	823	-80%
	farm	3	8	156%	3	24	717%	3	33	988%	4	37	925%
	light commercial	244	74	-70%	252	211	-16%	274	336	23%	355	350	-2%
	logging	19	35	85%	23	29	30%	32	32	0%	43	32	-26%
	airport service	1	3	354%	0	4	1129%	0	5	1523%	0	5	1417%
	railway maintenance	0	NA	NA	0	NA	NA	0	NA	NA	0	NA	NA
	recreational marine vessels	1,885	1,260	-33%	2,508	1,909	-24%	1,940	3,103	60%	2,000	3,687	84%
	Subtotal: Non-Road Gasoline	**5,605**	**2,642**	**-53%**	**6,630**	**3,512**	**-47%**	**6,955**	**4,565**	**-34%**	**7,285**	**5,309**	**-27%**
Non-Road Diesel	recreational	28	NA	NA	32	NA	NA	32	NA	NA	27	NA	NA
	construction	9,678	10,520	9%	6,813	7,089	4%	5,373	5,098	-5%	2,651	3,267	23%
	industrial	1,650	2,164	31%	1,318	1,659	26%	890	1,370	54%	215	780	263%
	lawn & garden	488	206	-58%	581	157	-73%	492	120	-76%	348	4	-99%
	farm	2,027	4,829	138%	1,743	3,218	85%	1,070	2,227	108%	577	1,296	125%
	light commercial	1,023	912	-11%	1,124	686	-39%	1,017	578	-43%	667	346	-48%
	logging	230	646	181%	76	225	194%	37	137	275%	3	83	2405%
	airport service	163	120	-26%	119	102	-14%	87	89	3%	33	54	64%
	railway maintenance	55	NA	NA	56	NA	NA	45	NA	NA	29	NA	NA
	recreational marine vessels	55	23	-59%	68	23	-65%	57	29	-48%	54	35	-34%
	Subtotal: Non-Road Diesel	**15,398**	**19,419**	**26%**	**11,930**	**13,160**	**10%**	**9,099**	**9,649**	**6%**	**4,604**	**5,865**	**27%**
Other	liquified petroleum gas	86	NA	NA	118	NA	NA	167	NA	NA	229	NA	NA
	compressed natural gas	12	57	376%	15	66	341%	19	73	274%	25	80	218%
	Subtotal: Other Sources	**98**	**57**	**-42%**	**133**	**66**	**-51%**	**186**	**73**	**-61%**	**254**	**80**	**-68%**
TOTAL: ALL SOURCES		**21,101**	**22,118**	**5%**	**18,692**	**16,738**	**-10%**	**16,240**	**14,287**	**-12%**	**12,142**	**11,254**	**-7%**

Exhibit D-7. Comparison of EPA Section 812 and ARB SO_2 Emissions for California, tpy

		1990			2000			2010			2020		
TIER 2 NAME	**TIER 3 NAME**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**	**EPA**	**ARB**	**Percent Difference**
Non-Road Gasoline	recreational	57	184	222%	63	43	-32%	10	48	355%	14	53	294%
	construction	31	12	-63%	26	10	-60%	2	11	387%	3	12	350%
	industrial	72	48	-33%	35	49	42%	2	54	3297%	1	57	9811%
	lawn & garden	624	127	-80%	666	150	-77%	67	170	155%	81	191	134%
	farm	3	10	209%	4	9	108%	0	10	2355%	0	10	2220%
	light commercial	174	53	-70%	203	55	-73%	22	61	179%	28	65	128%
	logging	1	5	326%	1	3	138%	0	3	2099%	0	3	1566%
	airport service	1	5	759%	1	7	1045%	0	8	16106%	0	9	15133%
	railway maintenance	0	NA	NA	0	NA	NA	0	NA	NA	0	NA	NA
	recreational marine vessels	127	123	-3%	158	153	-3%	15	185	1112%	17	208	1118%
	Subtotal: Non-Road Gasoline	**1,091**	**566**	**-48%**	**1,156**	**479**	**-59%**	**119**	**551**	**363%**	**144**	**609**	**321%**
Non-Road Diesel	recreational	14	NA	NA	16	NA	NA	2	NA	NA	0	NA	NA
	construction	7,718	9,421	22%	7,470	86	-99%	786	96	-88%	56	100	79%
	industrial	1,405	1,508	7%	1,701	13	-99%	170	14	-92%	11	14	25%
	lawn & garden	411	0	-100%	538	0	-100%	63	0	-100%	5	0	-100%
	farm	1,054	7,047	569%	1,332	348	-74%	123	36	-71%	9	35	297%
	light commercial	784	700	-11%	952	6	-99%	99	7	-93%	8	7	-5%
	logging	181	1,037	472%	126	3	-98%	8	3	-63%	0	3	703%
	airport service	111	3	-97%	146	0	-100%	17	1	-93%	1	1	9%
	railway maintenance	28	NA	NA	34	NA	NA	3	NA	NA	0	NA	NA
	recreational marine vessels	276	2	-99%	347	0	-100%	56	0	-100%	12	0	-100%
	Subtotal: Non-Road Diesel	**11,982**	**19,719**	**65%**	**12,662**	**457**	**-96%**	**1,327**	**157**	**-88%**	**104**	**161**	**55%**
Other	liquefied petroleum gas	20	NA	NA	27	NA	NA	33	NA	NA	43	NA	NA
	compressed natural gas	2	6	163%	3	6	118%	3	7	98%	5	7	57%
	Subtotal: Other Sources	**22**	**6**	**-73%**	**30**	**6**	**-80%**	**36**	**7**	**-81%**	**48**	**7**	**-85%**
TOTAL: ALL SOURCES		**13,095**	**20,291**	**55%**	**13,849**	**942**	**-93%**	**1,483**	**715**	**-52%**	**296**	**776**	**163%**

Pechan reviewed the differences resulting for specific equipment categories, focusing on those categories exhibiting the largest differences. In cases where category differences are relatively consistent among pollutants and for all years, this appears to be due in part to differences in base year engine populations between the two models. For example, ARB consistently reports at least 50 percent less emissions for all pollutants (except SO_2) for the gasoline lawn and garden equipment category.

Pechan noted the following equipment categories exhibiting relatively consistent differences among pollutants and years:

- Gasoline lawn and garden;
- Gasoline commercial; and
- Diesel farm.

Note that these trends did not hold for future year SO_2 emissions where they held for other pollutants, so the discussion below does not apply to SO_2. Differences in SO_2 emissions will be addressed separately, since SO_2 emissions are largely dependent on fuel sulfur content levels used as input to the emissions models.

To examine the differences in populations, Pechan obtained equipment populations (Alexis, 2005) used as the basis for ARB's emission estimates reported in *Emission Inventory Data - Almanac Emission Projection Data.* A comparison of EPA and ARB equipment populations at the Tier 3 level is shown in Exhibit D-8.

Gasoline Lawn and Garden

Statewide gasoline lawn and garden equipment populations are estimated by ARB to be one-half or less than EPA's NONROAD model. ARB estimates about 5 million engines, while NONROAD estimates 10 million. ARB's differences for the lawn and garden category explain much of the differences in the overall nonroad inventory. This is especially the case for VOC and CO where this category accounts for a significant percentage of the mass emissions, and to a lesser extent for $PM_{2.5}$. By way of example, replacing 2000 EPA estimates with ARB-equivalent estimates for VOC results in an overall difference of 5 percent between ARB and EPA (compared to 28 percent), and for CO results in an overall difference of 19 percent (compared to 57 percent).

In addition, Gasoline 4-Stroke Commercial Turf Equipment (SCC 2265004071) was not included as an equipment application in ARB's report, OFFROAD Modeling Change Technical Memo (ARB, 2003). This equipment type was a significant contributor to Statewide California VOC emissions per EPA's Section 812 study based on NONROAD (accounted for 13 percent of total gasoline lawn and garden VOC emissions).

Exhibit D-8. Comparison of EPA Section 812 and ARB Equipment Populations for California

TIER 2 NAME	TIER 3 NAME	1990 EPA	1990 ARB	1990 Percent Difference	2000 EPA	2000 ARB	2000 Percent Difference	2010 EPA	2010 ARB	2010 Percent Difference	2020 EPA	2020 ARB	2020 Percent Difference
Non-Road Gasoline	recreational	474,527	NA	NA	552,109	NA	NA	1,219,027	NA	NA	1,507,163	NA	NA
	construction	103,825	85,581	-18%	90,549	86,980	-4%	105,142	96,658	-8%	118,557	100,203	-15%
	industrial	36,351	24,770	-32%	17,229	25,767	50%	10,049	28,356	182%	3,534	29,427	733%
	lawn & garden	8,469,006	4,250,477	-50%	10,173,873	4,977,790	-51%	12,836,281	5,702,750	-56%	15,666,277	6,459,540	-59%
	farm	20,989	153,754	633%	27,241	163,994	502%	32,340	180,480	458%	38,909	194,589	400%
	light commercial	618,856	395,988	-36%	800,502	411,909	-49%	1,119,012	458,263	-59%	1,458,661	476,339	-67%
	logging	9,875	20,801	111%	11,180	11,961	7%	15,655	11,961	-24%	21,148	11,961	-43%
	airport service	226	1,832	710%	247	2,426	884%	289	3,001	939%	334	3,208	861%
	railway maintenance	1,347	NA	NA	1,524	NA	NA	1,759	NA	NA	2,009	NA	NA
	recreational marine vessels	751,069	748,406	0%	858,994	892,854	4%	958,501	1,054,957	10%	1,063,961	1,160,254	9%
	Subtotal: Non-Road Gasoline	**10,486,071**	**5,681,609**	**-46%**	**12,533,447**	**6,573,682**	**-48%**	**16,298,055**	**7,536,425**	**-54%**	**19,880,555**	**8,435,521**	**-58%**
Non-Road Diesel	recreational	2,608	NA	NA	3,250	NA	NA	4,375	NA	NA	5,572	NA	NA
	construction	155,013	160,741	4%	164,009	168,571	3%	238,214	188,342	-21%	319,417	195,436	-39%
	industrial	37,045	51,209	38%	48,665	57,056	17%	68,023	61,832	-9%	90,395	62,661	-31%
	lawn & garden	40,614	37,811	-7%	58,174	44,248	-24%	93,681	50,685	-46%	131,506	57,443	-56%
	farm	35,770	192,098	437%	49,330	195,940	297%	62,779	186,335	197%	79,383	176,762	123%
	light commercial	88,604	51,858	-41%	117,606	53,736	-54%	168,852	59,506	-65%	223,502	61,789	-72%
	logging	1,308	4,844	270%	996	2,785	180%	910	2,785	206%	866	2,785	222%
	airport service	1,532	1,492	-3%	2,201	1,973	-10%	3,510	2,436	-31%	4,902	2,616	-47%
	railway maintenance	938	NA	NA	1,235	NA	NA	1,746	NA	NA	2,289	NA	NA
	recreational marine vessels	17,096	20,134	18%	21,509	19,700	-8%	28,952	19,858	-31%	36,872	20,748	-44%
	Subtotal: Non-Road Diesel	**380,526**	**520,188**	**37%**	**466,976**	**544,009**	**16%**	**671,042**	**571,780**	**-15%**	**894,705**	**580,240**	**-35%**
Other	liquified petroleum gas	49,282	NA	NA	68,336	NA	NA	101,369	NA	NA	140,666	NA	NA
	compressed natural gas	7,074	NA	NA	9,004	NA	NA	12,015	NA	NA	15,752	NA	NA
	Subtotal: Other Sources	**56,356**	**0**	**-100%**	**77,340**	**0**	**-100%**	**113,385**	**0**	**-100%**	**156,418**	**0**	**-100%**
TOTAL: ALL SOURCES		**10,922,953**	**6,201,796**	**-43%**	**13,077,762**	**7,117,691**	**-46%**	**17,082,482**	**8,108,204**	**-53%**	**20,931,678**	**9,015,760**	**-57%**

It should be noted that ARB recently conducted a Statewide survey of California households to determine the population and usage of residential and commercial lawn and garden equipment. The results show a revised estimate of approximately 13 million pieces of equipment (ARB, 2003). These revised equipment populations are expected to result in increased VOC and CO emissions for ARB, making their OFFROAD model results more comparable to EPA's estimates.

Gasoline Light Commercial

Gasoline light commercial emissions from ARB are also consistently lower, with a few exceptions (e.g., NO_x in 1990, and $PM_{2.5}$ in 2010). Light commercial is the second highest equipment category contributing to CO emissions (lawn and garden is first), and this category accounts for about 9 percent of the total VOC emissions from gasoline engines. Equipment populations for this category are about 49 percent lower than EPA estimates in 2000, and up to 67 percent lower than EPA estimates in 2020. ARB VOC, NO_x, and CO emissions average about 56 percent lower in 2000, and 65 percent lower in 2020. Based on available ARB documentation for this category, the source of the original national population data is PSR for both OFFROAD and NONROAD, so the source of the difference is likely in how State-level populations are estimated from national populations (PSR does not report State-level equipment populations). For NONROAD, commercial equipment populations in California are estimated to be 12 percent of the national total, using the number of wholesale establishments as a surrogate allocation factor.

Diesel Farm Equipment

Diesel farm equipment emissions from ARB are consistently 200 to 300 percent higher for VOC, CO, NO_x, and about 100 percent higher for $PM_{2.5}$. In examining the equipment populations for diesel farm equipment, the ARB estimates are considerably higher than EPA estimates. For example in 2000, equipment populations are close to 300 percent higher than EPA according to ARB (195,940 versus 49,330). These discrepancies result from differences in the source of the population estimates. ARB estimates populations of agricultural tractors, balers and combines based on the United States Department of Agriculture's 1997 Census of Agriculture. Agricultural tractors account for the majority of total agricultural equipment activity and emissions. EPA uses PSR engine sales data to estimate national populations for all agricultural equipment, allocated to counties using surrogate data on acres of crop harvested.

SCENARIO YEAR COMPARISON

Certain equipment categories show comparable estimates for the base year. However, in comparing future year emissions, the ARB estimates become increasingly lower for each projection year. This is the case for the gasoline recreational marine category, which would result from either a lower growth rate assumed by ARB, or more stringent California engine standards than EPA for this category. A discussion of this category, and other categories whose differences vary by analysis year, follows below.

Recreational Marine

In base year 2000, ARB's gasoline recreational marine VOC emissions are only 3 percent lower than EPA. However, in 2010 and 2020, ARB estimates are 14 percent and 39 percent lower, respectively, than EPA VOC estimates. ARB has implemented more stringent exhaust emission standards for SI marine engines sold for use in California. The California outboard/personal watercraft (OB/PWC) standards accelerate the Federal 2006 standard to 2001 in California, then introduce two further tiers of emission standards. These two tiers begin with the 2004 and 2008 model years and are about 20 percent and 65 percent, respectively, lower than the Federal 2006 OB/PWC HC+ NO_x standards. As such, cleaner engines are introduced into the fleet earlier and result in overall fleet-average emissions that are lower than emissions resulting from EPA standards in 2010 and 2020.

Diesel Construction Equipment

For some pollutants, base year estimates show greater differences than future year emissions. For example, for diesel construction NO_x emissions, 1990 and 2000 year estimates are considerably higher than EPA (94 percent and 69 percent respectively). Given that ARB and EPA engine populations are comparable for these years, these differences are likely due to different activity rates, different emission rates, or possibly a different horsepower distribution of the modeled engines. In examining specific equipment applications, it was found that for the highest NO_x emitting diesel SCC, Diesel Rubber Tire Loaders, ARB estimates annual activity to be 1346 hours per year, compared with EPA's estimate of 761 hours per year (ARB is 77 percent higher) (ARB, 2005b). This activity difference may explain in part the emission differences observed.

These differences become less pronounced in 2010 and 2020, which is likely due in part to ARB's lower growth rate for diesel construction (and diesel engines in general). For example, ARB's annual average growth rate between 2000 and 2020 for diesel construction equipment populations is about 1 percent, compared to EPA's annual growth rate of about 5 percent for this source type.

Sulfur Dioxide

SO_2 emissions are proportional to fuel consumption and fuel sulfur content levels used as input to the emissions models. The SO_2 discrepancies are due in part to differences between California's and EPA's fuel sulfur program (i.e., required fuel sulfur levels and phase-in schedule). The fuel sulfur content levels used as input to the ARB's OFFROAD model were obtained from public documentation on ARB's web site (ARB, 2005c). Exhibit D-9 presents a summary of ARB's fuel sulfur levels compared to EPA for gasoline and diesel engines for all four analysis years.

Exhibit D-9. Nonroad Gasoline and Diesel Fuel Sulfur Levels, ppm

	1990	2000	2010	2020
Gasoline				
EPA	339	339	30	30
ARB	220	22	15	15
Diesel				
EPA	2,500	2,284	170	11
ARB	3,000	140	15	15

Exhibit D-10 compares the trend in EPA's and ARB's SO_2 emissions for all gasoline engines, and also shows the fuel sulfur levels used by ARB and EPA for each analysis year. For 1990 and 2000, the SO_2 emissions vary with the fuel sulfur input values. In 1990 and the base year, ARB assumes a lower fuel sulfur content level than EPA. However, these emissions are estimated by ARB to increase slightly in 2010 and 2020, whereas EPA models a sharp drop in SO_2 due to the change in gasoline fuel sulfur levels required by their Tier 2 standard (i.e., from 339 ppm sulfur in 2000 to 30 ppm in 2010 and 2020).

Exhibit D-10. Nonroad Gasoline SO_2 Emissions and Sulfur Content

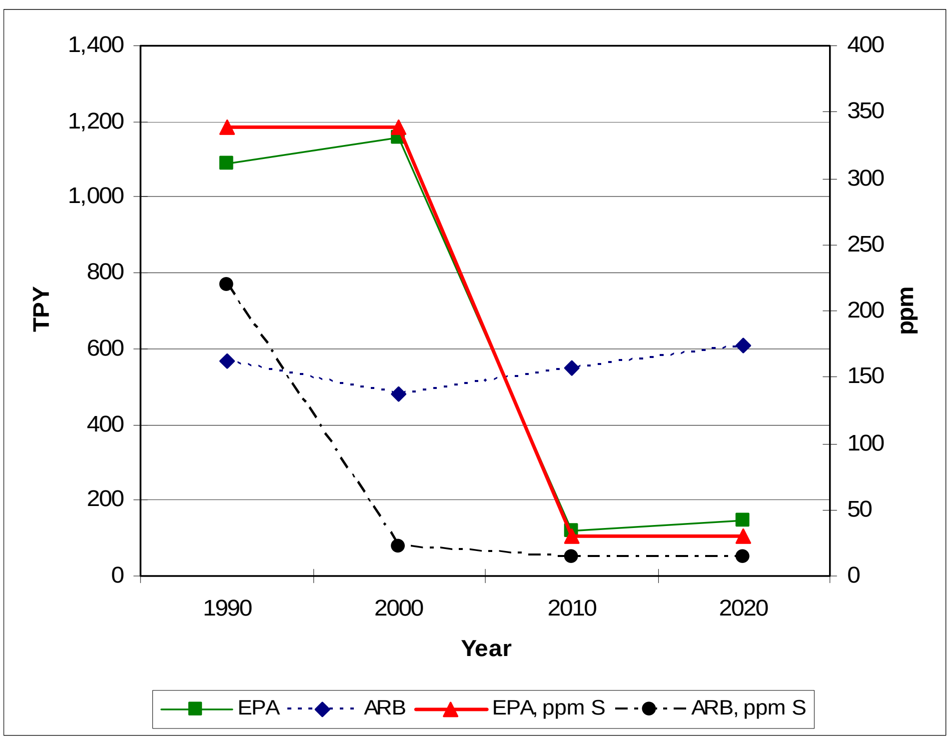
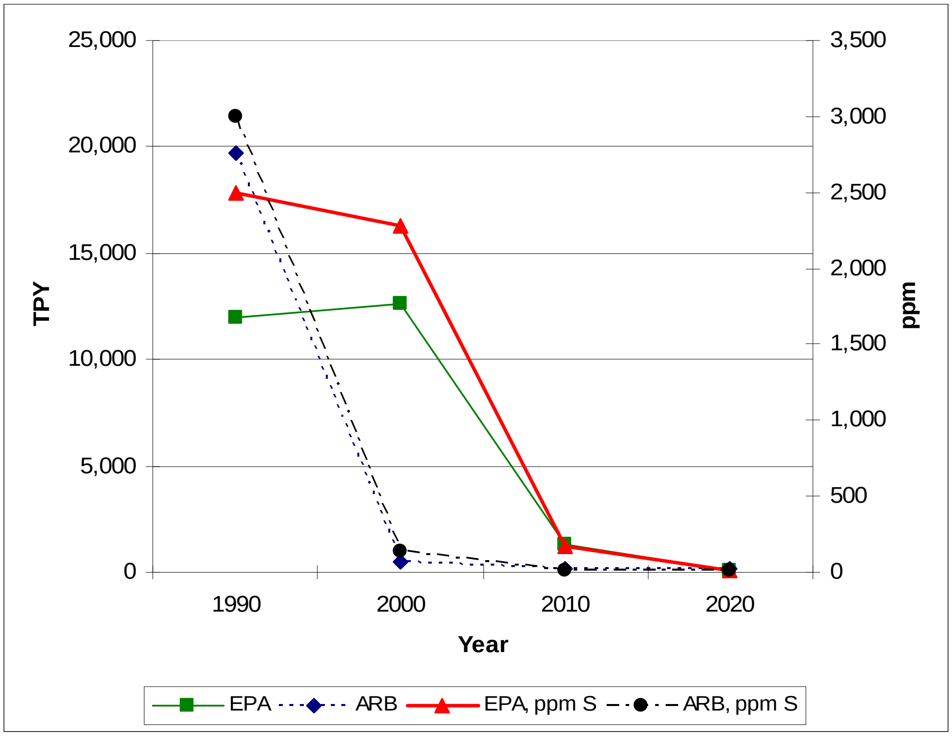


Exhibit D-11 shows EPA and ARB SO_2 emissions for diesel engines. The SO_2 emissions for ARB and EPA both track reasonably well with the fuel sulfur levels also presented in Exhibit D-11. ARB's 1990 diesel SO_2 emissions are considerably higher than EPA. In 2000, ARB estimates much lower SO_2 emissions than EPA, that level off somewhat in

2010 and 2020. In contrast, EPA estimates a sharp drop in SO_2 due to the change in diesel fuel sulfur levels required from the Clean Air Diesel Rule (see Exhibit D-9).

Exhibit D-11. Nonroad Diesel SO_2 Emissions and Sulfur Content



CONCLUSIONS

Differences between base and future year ARB and EPA nonroad emission estimates for California can be explained by differences in equipment activity, category-specific future emission standards, and variations in fuel input data (e.g., fuel sulfur content), depending on the equipment category and pollutant.

In examining equipment activity levels, Pechan first focused on obtaining equipment populations from ARB for the majority of nonroad categories. (A more comprehensive comparison of ARB and EPA nonroad emission models would include investigations into differences in annual hours of use, load factors, as well as horsepower distributions for all applications. The mix of equipment populations by horsepower can have a large impact on the resulting emissions, since emission rates and emission standards apply based on engine type and size, and not based on SCC.) The initial emission estimates that ARB provided were not organized by SCC or horsepower, but at a more aggregate category level. As such, it was not possible for Pechan to do a comprehensive comparison of SCC and horsepower distributions, but any differences in this assumed distribution are expected to result in differences in emissions.

After examining emission standards and equipment populations for categories exhibiting the largest differences, Pechan did examine some of the other activity variables (e.g., annual hours of use and load factor) by SCC where readily available on ARB's web site.

Differences in these two activity variables, as well as equipment populations, appear to be causing some of the observed differences.

Using ARB OFFROAD based emissions in place of EPA's NONROAD emissions will result in lower levels of VOC (up to 40 percent lower) and CO (up to 75 percent lower). These differences are expected to be less if updated California survey results for lawn and garden equipment are incorporated. ARB's NO_x estimates are higher for all scenario years (from 98 percent higher in 1990 to about 20 percent higher for the years 2010 and 2020). Using California's fuel sulfur levels specified by ARB in place of the national defaults for California would result in more comparable emissions for SO_2. The emission factors would then be consistent between NONROAD and ARB OFFROAD, but differences in SO_2 emissions will remain where there are differences in activity estimates for some equipment categories.

REFERENCES

Alexis, 2005: Andy Alexis, California Air Resources Board, *Off-road Population 1990 to 2010.xls*, spreadsheet obtained via e-mail, November 28, 2005.

ARB, 2003: California Air Resources Board, OFFROAD Modeling Change Technical Memo, Subject: Change in Population and Activity Factors for Lawn and Garden Equipment, M. Cordero and W. Wong, June 13, 2003.

ARB, 2005a: Air Resources Board, *Emission Inventory Data - Almanac Emission Projection Data*, available at http://www.arb.ca.gov/ei/emsmain/reportform.htm, nonroad sector data for 1990, 2000, 2010, and 2020 downloaded July 22, 2005.

ARB, 2005b: California Air Resources Board Mobile Source Mailout MSC #99-32, Data spreadsheet "Large Diesel CA data.xls," downloaded from http://www.arb.ca.gov/msei/off-road/pubs.htm on November 4, 2005.

ARB, 2005c: California Air Resources Board, OFFROAD Modeling Change Technical Memo, Subject: OFFROAD Exhaust Emissions Inventory Fuel Correction Factors, T. Sicat, July 25, 2005.

Exhibit D-12. EPA Tier Category Assignments for ARB Nonroad Categories

TIER2	TIER2NAME	TIER3	TIER3NAME	EIC	EICSUM	EICSOU	EICMAT	EICSUB
01	Non-Road Gasoline	01	recreational	850-870-1100-0000	850-OFF-ROAD REC VEHICLES	870-SNOWMOBILES	1100-GASOLINE	0000-SUB-CATEGORY UNSPECIFIED
01	Non-Road Gasoline	01	recreational	850-872-1100-0000	850-OFF-ROAD REC VEHICLES	872-OFF-ROAD MOTORCYCLES	1100-GASOLINE	0000-SUB-CATEGORY UNSPECIFIED
01	Non-Road Gasoline	01	recreational	850-874-1100-0000	850-OFF-ROAD REC VEHICLES	874-ALL-TERRAIN VEHICLES (ATV'S)	1100-GASOLINE	0000-SUB-CATEGORY UNSPECIFIED
01	Non-Road Gasoline	01	recreational	850-876-1100-0000	850-OFF-ROAD REC VEHICLES	876-FOUR-WHEEL DRIVE VEHICLES	1100-GASOLINE	0000-SUB-CATEGORY UNSPECIFIED
01	Non-Road Gasoline	02	construction	860-887-1100-0020	860-OFF-ROAD EQUIPMENT	887-CONSTRUCTION AND MINING EQUIPMENT	1100-GASOLINE	0020-TWO-STROKE EXHAUST
01	Non-Road Gasoline	02	construction	860-887-1100-0021	860-OFF-ROAD EQUIPMENT	887-CONSTRUCTION AND MINING EQUIPMENT	1100-GASOLINE	0021-TWO-STROKE EVAPORATIVE
01	Non-Road Gasoline	02	construction	860-887-1100-0040	860-OFF-ROAD EQUIPMENT	887-CONSTRUCTION AND MINING EQUIPMENT	1100-GASOLINE	0040-FOUR-STROKE EXHAUST
01	Non-Road Gasoline	02	construction	860-887-1100-0041	860-OFF-ROAD EQUIPMENT	887-CONSTRUCTION AND MINING EQUIPMENT	1100-GASOLINE	0041-FOUR-STROKE EVAPORATIVE
01	Non-Road Gasoline	03	industrial	860-884-1100-0040	860-OFF-ROAD EQUIPMENT	884-TRANSPORT REFRIGERATION UNITS	1100-GASOLINE	0040-FOUR-STROKE EXHAUST
01	Non-Road Gasoline	03	industrial	860-884-1100-0041	860-OFF-ROAD EQUIPMENT	884-TRANSPORT REFRIGERATION UNITS	1100-GASOLINE	0041-FOUR-STROKE EVAPORATIVE
01	Non-Road Gasoline	03	industrial	860-886-1100-0020	860-OFF-ROAD EQUIPMENT	886-INDUSTRIAL EQUIPMENT	1100-GASOLINE	0020-TWO-STROKE EXHAUST
01	Non-Road Gasoline	03	industrial	860-886-1100-0021	860-OFF-ROAD EQUIPMENT	886-INDUSTRIAL EQUIPMENT	1100-GASOLINE	0021-TWO-STROKE EVAPORATIVE
01	Non-Road Gasoline	03	industrial	860-886-1100-0040	860-OFF-ROAD EQUIPMENT	886-INDUSTRIAL EQUIPMENT	1100-GASOLINE	0040-FOUR-STROKE EXHAUST
01	Non-Road Gasoline	03	industrial	860-886-1100-0041	860-OFF-ROAD EQUIPMENT	886-INDUSTRIAL EQUIPMENT	1100-GASOLINE	0041-FOUR-STROKE EVAPORATIVE
01	Non-Road Gasoline	04	lawn & garden	860-883-1100-0020	860-OFF-ROAD EQUIPMENT	883-LAWN AND GARDEN EQUIPMENT	1100-GASOLINE	0020-TWO-STROKE EXHAUST
01	Non-Road Gasoline	04	lawn & garden	860-883-1100-0021	860-OFF-ROAD EQUIPMENT	883-LAWN AND GARDEN EQUIPMENT	1100-GASOLINE	0021-TWO-STROKE EVAPORATIVE
01	Non-Road Gasoline	04	lawn & garden	860-883-1100-0040	860-OFF-ROAD EQUIPMENT	883-LAWN AND GARDEN EQUIPMENT	1100-GASOLINE	0040-FOUR-STROKE EXHAUST
01	Non-Road Gasoline	04	lawn & garden	860-883-1100-0041	860-OFF-ROAD EQUIPMENT	883-LAWN AND GARDEN EQUIPMENT	1100-GASOLINE	0041-FOUR-STROKE EVAPORATIVE
01	Non-Road Gasoline	05	farm	870-893-1100-0040	870-FARM EQUIPMENT	893-AGRICULTURAL EQUIPMENT	1100-GASOLINE	0040-FOUR-STROKE EXHAUST
01	Non-Road Gasoline	05	farm	870-893-1100-0041	870-FARM EQUIPMENT	893-AGRICULTURAL EQUIPMENT	1100-GASOLINE	0041-FOUR-STROKE EVAPORATIVE
01	Non-Road Gasoline	06	light commercial	860-885-1100-0020	860-OFF-ROAD EQUIPMENT	885-LIGHT COMMERCIAL EQUIPMENT	1100-GASOLINE	0020-TWO-STROKE EXHAUST
01	Non-Road Gasoline	06	light commercial	860-885-1100-0021	860-OFF-ROAD EQUIPMENT	885-LIGHT COMMERCIAL EQUIPMENT	1100-GASOLINE	0021-TWO-STROKE EVAPORATIVE

TIER2	TIER2NAME	TIER3	TIER3NAME	EIC	EICSUM	EICSOU	EICMAT	EICSUB
01	Non-Road Gasoline	06	light commercial	860-885-1100-0040	860-OFF-ROAD EQUIPMENT	885-LIGHT COMMERCIAL EQUIPMENT	1100-GASOLINE	0040-FOUR-STROKE EXHAUST
01	Non-Road Gasoline	06	light commercial	860-885-1100-0041	860-OFF-ROAD EQUIPMENT	885-LIGHT COMMERCIAL EQUIPMENT	1100-GASOLINE	0041-FOUR-STROKE EVAPORATIVE
01	Non-Road Gasoline	07	logging	860-888-1100-0020	860-OFF-ROAD EQUIPMENT	888-LOGGING EQUIPMENT	1100-GASOLINE	0020-TWO-STROKE EXHAUST
01	Non-Road Gasoline	07	logging	860-888-1100-0021	860-OFF-ROAD EQUIPMENT	888-LOGGING EQUIPMENT	1100-GASOLINE	0021-TWO-STROKE EVAPORATIVE
01	Non-Road Gasoline	07	logging	860-888-1100-0040	860-OFF-ROAD EQUIPMENT	888-LOGGING EQUIPMENT	1100-GASOLINE	0040-FOUR-STROKE EXHAUST
01	Non-Road Gasoline	07	logging	860-888-1100-0041	860-OFF-ROAD EQUIPMENT	888-LOGGING EQUIPMENT	1100-GASOLINE	0041-FOUR-STROKE EVAPORATIVE
01	Non-Road Gasoline	08	airport service	860-889-1100-0040	860-OFF-ROAD EQUIPMENT	889-AIRPORT GROUND SUPPORT EQUIPMENT	1100-GASOLINE	0040-FOUR-STROKE EXHAUST
01	Non-Road Gasoline	08	airport service	860-889-1100-0041	860-OFF-ROAD EQUIPMENT	889-AIRPORT GROUND SUPPORT EQUIPMENT	1100-GASOLINE	0041-FOUR-STROKE EVAPORATIVE
01	Non-Road Gasoline	10	recreational marine vessels	840-864-1100-0020	840-RECREATIONAL BOATS	864-RECREATIONAL BOATS	1100-GASOLINE	0020-TWO-STROKE EXHAUST
01	Non-Road Gasoline	10	recreational marine vessels	840-864-1100-0021	840-RECREATIONAL BOATS	864-RECREATIONAL BOATS	1100-GASOLINE	0021-TWO-STROKE EVAPORATIVE
01	Non-Road Gasoline	10	recreational marine vessels	840-864-1100-0040	840-RECREATIONAL BOATS	864-RECREATIONAL BOATS	1100-GASOLINE	0040-FOUR-STROKE EXHAUST
01	Non-Road Gasoline	10	recreational marine vessels	840-864-1100-0041	840-RECREATIONAL BOATS	864-RECREATIONAL BOATS	1100-GASOLINE	0041-FOUR-STROKE EVAPORATIVE
02	Non-Road Diesel	02	construction	860-887-1210-0000	860-OFF-ROAD EQUIPMENT	887-CONSTRUCTION AND MINING EQUIPMENT	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED
02	Non-Road Diesel	03	industrial	860-884-1210-0000	860-OFF-ROAD EQUIPMENT	884-TRANSPORT REFRIGERATION UNITS	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED
02	Non-Road Diesel	03	industrial	860-886-1210-0000	860-OFF-ROAD EQUIPMENT	886-INDUSTRIAL EQUIPMENT	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED
02	Non-Road Diesel	03	industrial	860-890-1210-0000	860-OFF-ROAD EQUIPMENT	890-DREDGING	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED
02	Non-Road Diesel	03	industrial	860-891-1210-0000	860-OFF-ROAD EQUIPMENT	891-OIL DRILLING AND WORKOVER	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED
02	Non-Road Diesel	03	industrial	860-892-1210-0000	860-OFF-ROAD EQUIPMENT	892-MILITARY TACTICAL SUPPORT EQUIPMENT	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED
02	Non-Road Diesel	03	industrial	860-995-1210-0000	860-OFF-ROAD EQUIPMENT	995-OTHER	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED
02	Non-Road Diesel	04	lawn & garden	860-883-1210-0000	860-OFF-ROAD EQUIPMENT	883-LAWN AND GARDEN EQUIPMENT	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED
02	Non-Road Diesel	05	farm	870-893-1210-0000	870-FARM EQUIPMENT	893-AGRICULTURAL EQUIPMENT	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED

TIER2	TIER2NAME	TIER3	TIER3NAME	EIC	EICSUM	EICSOU	EICMAT	EICSUB
02	Non-Road Diesel	06	light commercial	860-885-1210-0000	860-OFF-ROAD EQUIPMENT	885-LIGHT COMMERCIAL EQUIPMENT	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED
02	Non-Road Diesel	07	logging	860-888-1210-0000	860-OFF-ROAD EQUIPMENT	888-LOGGING EQUIPMENT	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED
02	Non-Road Diesel	08	airport service	860-889-1210-0000	860-OFF-ROAD EQUIPMENT	889-AIRPORT GROUND SUPPORT EQUIPMENT	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED
02	Non-Road Diesel	10	recreational marine vessels	840-864-1210-0000	840-RECREATIONAL BOATS	864-RECREATIONAL BOATS	1210-DIESEL	0000-SUB-CATEGORY UNSPECIFIED
06	Other	02	compressed natural gas	860-885-0110-0000	860-OFF-ROAD EQUIPMENT	885-LIGHT COMMERCIAL EQUIPMENT	0110-NATURAL GAS	0000-SUB-CATEGORY UNSPECIFIED
06	Other	02	compressed natural gas	860-886-0110-0000	860-OFF-ROAD EQUIPMENT	886-INDUSTRIAL EQUIPMENT	0110-NATURAL GAS	0000-SUB-CATEGORY UNSPECIFIED
06	Other	02	compressed natural gas	860-889-0110-0000	860-OFF-ROAD EQUIPMENT	889-AIRPORT GROUND SUPPORT EQUIPMENT	0110-NATURAL GAS	0000-SUB-CATEGORY UNSPECIFIED

NOTES: EIC = ARB's Emission Inventory Code

APPENDIX E

SENSITIVITY ANALYSIS: INPUTS FOR OFFROAD CONSTRUCTION EQUIPMENT

APPENDIX E | SENSITIVITY ANALYSIS: INPUTS FOR OFFROAD CONSTRUCTION EQUIPMENT

INTRODUCTION

EPA's NONROAD model was determined by the EPA Science Advisory Board Air Quality Modeling Subcommittee (AQMS) to be the most appropriate tool for estimating non-road mobile source emissions outside of California. However, recent studies by States suggest that activity factors for construction vehicles may differ substantially from the values included in the NONROAD model. Based on these findings, the AQMS suggested that the project team conduct sensitivity analyses that specifically address this uncertainty. Nonroad "activity factors" are comprised of several variables, including equipment population, engine horsepower and load factor, and annual hours of use. Some of the studies questioning the validity of the NONROAD activity factors concluded that NONROAD underestimates annual hours of use per unit of equipment and overestimates total equipment populations. Because these changes offset each other (at least partially), the overall effect on activity is unclear.

Based on the emission estimation equation, the relationship between emissions and each activity variable is linear. Activity for nonroad equipment is calculated using the following equation:

Activity = Power x Load Factor x Time x Pop

Activity	=	activity (horsepower [hp]-hours)
Power	=	average rated engine power (hp)
Load Factor	=	engine load factor (average proportion of rated power)
Time	=	hours of use (hours)
Pop	=	equipment population

This analysis focuses on base year *with-CAAA* scenario emissions for 2000. Note that revisions to hours of use data also affect rates of scrappage and phase-in of new, cleaner engines, which will affect future year emissions.

To gauge the potential significance of these activity factors, Pechan compared year 2000 emissions developed from default activity inputs included in NONROAD with emissions developed from revised inputs from three local construction activity studies. The three specific studies include: (1) Lake Michigan Air Directors Consortium (LADCO) Nonroad Emissions Inventory Project; (2) Clark County-Wide Inventory of Non-road Engines Project; and (3) Houston-Galveston Area Diesel Construction Emissions Project.

Pechan first generated annual emission estimates for the geographic areas covered by the surveys using NONROAD2004 and all default data inputs. Pechan then adjusted the NONROAD model activity inputs using the reported survey results to generate revised emission estimates for comparison. This analysis focused on five priority construction equipment applications, or source classification codes (SCCs). In addition, because the base activity is the same for all pollutants, and differences in pollutant estimates are due to differences in emission rates, the analysis was limited to oxides of nitrogen (NO_x) emissions.

In summary, this analysis shows that local surveys of nonroad equipment populations and activity produce NO_x emission estimates that can be considerably higher or lower than estimates made using EPA's NONROAD model defaults. For both LADCO studies, overall NO_x emissions are higher in the local area study than in the section 812 analysis, as emissions increases for the three largest equipment types outweigh decreases in those for the other two equipment types studied.. For Clark County, much lower equipment populations for all surveyed source categories lead to a much lower estimate of construction equipment NO_x emissions for the area. Finally, for the Houston area study, lower estimated equipment activity for four equipment types contribute to a overall NO_x emission decrease for the equipment types studied.

Assuming that national populations estimated by NONROAD are a reliable measure of the total in-use national engine populations, lower estimates of equipment populations based on surveys in certain areas would be expected to be offset by increases in other areas. However, the differences observed at the local level suggest that there is considerable uncertainty in the construction equipment emission estimates for any individual geographic area. In addition, the differences also imply that use of NONROAD default data might lead to some errors in performing any local controls analysis to simulate how an area might respond to 8-hour ozone and $PM_{2.5}$ NAAQS control requirements. Control decisions would be expected to be significantly different in areas like Clark County, NV depending on whether national defaults or local survey data are used to determine the importance of off-road construction equipment.

SURVEY DATA COMPARISONS

Project Team member E.H. Pechan ran EPA's NONROAD2004 model (NR2004) to develop year 2000 *with-CAAA*NO_x emission estimates for geographic areas/studies provided in Exhibit E-1 (EPA, 2004). For the LADCO survey, Pechan compared State-level results for one State in the LADCO region (Ohio), as well as results for the entire five-State region. For the Clark County and Houston-Galveston surveys, county level results were compared.

Exhibit E-1. Construction Equipment Surveys Included in Analysis

Study	Region	Reference
Lake Michigan Air Directors Consortium (LADCO) Nonroad Emissions Inventory Project	Five States – Illinois, Indiana, Michigan, Ohio, Wisconsin	Pechan, 2004
Clark County-Wide Inventory of Non-road Engines Project	Clark County, Nevada	MACTEC, 2003
Houston-Galveston Area Diesel Construction Emissions Project	8 Texas Counties – Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller	ERG, 2000

These runs were performed using all NR2004 defaults. Pechan compared the survey results to the Section 812 results for five select construction source classification codes (SCCs), shown in Exhibit E-2. These SCCs typically rank as the top-emitters of NO_x when local or national emission inventories are prepared using default NONROAD model inputs.

Exhibit E-2. Priority SCCs for Construction Equipment Sensitivity Analysis

SCC	SCC Name
2270002036	Excavators
2270002060	Rubber Tire Loaders
2270002066	Tractors/Loaders/Backhoes
2270002069	Crawler Tractor/Dozers
2270002072	Skid Steer Loaders

Because the base activity is the same for all pollutants, and differences in pollutant estimates are due to differences in emission rates, the analysis was limited to NO_x emissions.

The results of default runs were compared with NR2004 results generated by varying the equipment population and annual hours of use values from the local surveys. The annual 2000 NO_x emissions resulting from data inputs collected for each of the four studies and the default NONROAD NO_x emissions are presented and discussed in the sections below.

For each study, the equipment populations and annual hours of use values are also compared with EPA defaults. Changes in total activity are represented by changes in these two variables only, since load factor and horsepower do not change. Percent differences in survey values compared to EPA defaults are shown graphically in bar charts. It should be noted, however, that the impact of activity changes on NO_x emissions will depend on the original values for population and hours of use, and how these two variables compare to each other before the adjustment. For example, if equipment populations are much higher than annual hours of use, then an equivalent percent change for usage will result in a negligible impact on emissions (see Clark County results below). Because the product of equipment populations and annual hours of use provides a more accurate indication of changes in total activity, these two variables are multiplied and compared as well.

STATE OF OHIO - LADCO STUDY

For this study, firms classified under specified SIC groupings were randomly surveyed using a computer assisted telephone interview (CATI) system. To scale the results to the LADCO region, equipment populations were estimated based on scaling factors derived from the survey results. Scaling factors were developed for each SIC/equipment type combination by dividing the number of pieces of equipment by the total number of employees. State-level employment by SIC was then multiplied by this scaling factor to yield an estimate of State-level SCC-level equipment populations.

Equipment-specific annual hours of use were estimated by multiplying hours of operation per week, by weeks of operation per year. Note that hours of use for all SCCs for the LADCO study was assumed to be 20 percent higher than the NR2004 default values based on a statistical analysis of results for all SCCs combined (the responses by SCC were not deemed statistically valid to make SCC-specific adjustments).

Exhibit E-3 compares the SCC-level population, annual hours of use (hereafter referred to as 'usage'), and NO_x emissions resulting from the NR2004 default inputs and the survey data. Exhibit E-4 displays in chart format the percent difference in population, usage, and NO_x emissions of survey results from NR2004 results. Percent difference is calculated using the following formula:

$$\%\ \mathit{Difference} = (\mathit{Survey\ Data} - \mathit{NR}2004\ \mathit{Data}) / \mathit{NR}2004\ \mathit{Data} \times 100$$

For Crawler Tractor/Dozers and Excavators, a 15 percent increase in equipment populations and 20 percent increase in usage results in NO_x increases of approximately 30 percent. Rubber-Tired Loaders show comparable, though slightly lower, equipment populations, but the increased usage results in a 15 percent NO_x increase. For Skid Steer Loaders and Tractors/Loaders/Backhoes, significant decreases in equipment populations are offset somewhat by the increased usage. NO_x emissions are about 65 to 40 percent lower for Skid Steer Loaders and Tractors/Loaders/Backhoes, respectively.

FIVE-STATE REGION - LADCO STUDY

In addition to the Ohio-specific results discussed above, results for all five States combined were analyzed as well. Exhibit E-5 compares the SCC-level population, usage, and NO_x emissions resulting from the NR2004 default inputs and the survey data. Exhibit E-6 displays the percent difference in activity and NO_x emissions of SCC-level survey results from NR2004 results.

For Crawler Tractor/Dozers, Rubber Tire Loaders and Excavators, increases for both usage and equipment populations between 20 and 40 percent higher result in NO_x increases around 40 to 60 percent higher than NR2004 default results. For Skid Steer Loaders and Tractors/Loaders/Backhoes, significant decreases in equipment populations are offset somewhat by the increased usage. NO_x emissions are about 60 to 30 percent lower for Skid Steer Loaders and Tractors/Loaders/Backhoes, respectively. Compared to Ohio results, region-wide the NO_x increases seen for three SCCs are higher, and the emission decreases observed for two SCCs are slightly lower.

CLARKCOUNTYNEVADA STUDY

The Clark County study attempted to survey 100 percent of the large construction firms (with revenues greater than $50 million), and a random sample of smaller firms owning equipment, as well as equipment rental companies. The data were collected using a mail-out survey with follow-up telephone calls. Equipment populations for surveyed establishments were extrapolated to the entire county based on employment data. Annual hours of use was calculated from the product of operating hours per day, operating days per week, and operating weeks per year, and weighted by the equipment populations reported by the respondent.

Exhibit E-7 compares the SCC-level population, usage, and NO_x emissions resulting from the NR2004 default inputs and the survey data obtained from the Clark County Study. Exhibit E-8 displays the percent difference in activity and NO_x emissions of survey results from NR2004 results.

For all SCCs, significant decreases in equipment populations are not offset by increases in usage. NO_x emissions predicted with the Clark County inputs are about 90 percent lower than EPA. This results because total activity, expressed as equipment populations multiplied by hours of use, is significantly lower as predicted by the survey results compared to NR2004 for each SCC (see Exhibit E-7).

EIGHT-COUNTY HOUSTON AREA – HOUSTON-GALVESTON STUDY

For this study, a survey was conducted of diesel construction equipment populations and activity within the eight county Houston area. Quantitative measures of company/organization market share or related metrics were obtained for survey respondents to use as a surrogate for extrapolating population values. Equipment usage data in hours per year were based on a number of sources, including engine clock hour data, labor records (e.g., hours for crane operators), estimator or field supervisor estimates, and fuel use records.

Exhibit E-9 compares the SCC-level population, usage, and NO_x emissions resulting from the NR2004 default inputs and the survey data obtained from the Houston-Galveston Study. Exhibit E-10 displays the percent difference in activity and NO_x emissions of survey results from NR2004 results.

For Skid Steer Loaders and Rubber Tire Loaders significant decreases in equipment populations are offset somewhat by the increased usage. NO_x emissions are about 80 and 40 percent lower for Skid Steer Loaders and Rubber Tire Loaders, respectively. For Tractors/Loaders/Backhoes, decreases in both equipment populations and usage result in NO_x decreases close to 60 percent. For Excavators, lower equipment populations outweigh higher usage to cause NO_x decreases of 15 percent. Finally, Crawler Tractor/Dozers show increased NO_x emissions due to higher equipment populations, offsetting lower usage.

Exhibit E-3. Activity and Emissions Comparison (Ohio-LADCO)

	Population		Hrs/Yr		Population * Hrs/Yr				NO_x, tpy		
EQUIPMENT	NR2004	LADCO	NR2004	LADCO	NR2004	LADCO	Difference (LADCO-NR2004)	% Difference (LADCO-NR2004)/ NR2004	NR2004	LADCO	% Difference
Skid Steer Loaders	23,122	6,573	818	982	18,913,548	6,454,388	-12,459,160	-66%	2,103	697	-67%
Crawler Tractor/Dozers	4,280	4,860	936	1,123	4,006,173	5,457,903	1,451,729	36%	4,687	6,167	32%
Tractors/Loaders/Backhoes	14,858	7,540	1,135	1,362	16,863,488	10,269,456	-6,594,032	-39%	3,239	1,884	-42%
Rubber Tire Loaders	6,162	6,094	761	913	4,689,586	5,564,263	874,678	19%	5,356	6,092	14%
Excavators	5,569	6,336	1,092	1,310	6,081,566	8,299,695	2,218,129	36%	4,356	5,688	31%

Exhibit E-4. Percent Difference in Activity and NO_x Emissions (Ohio-LADCO)

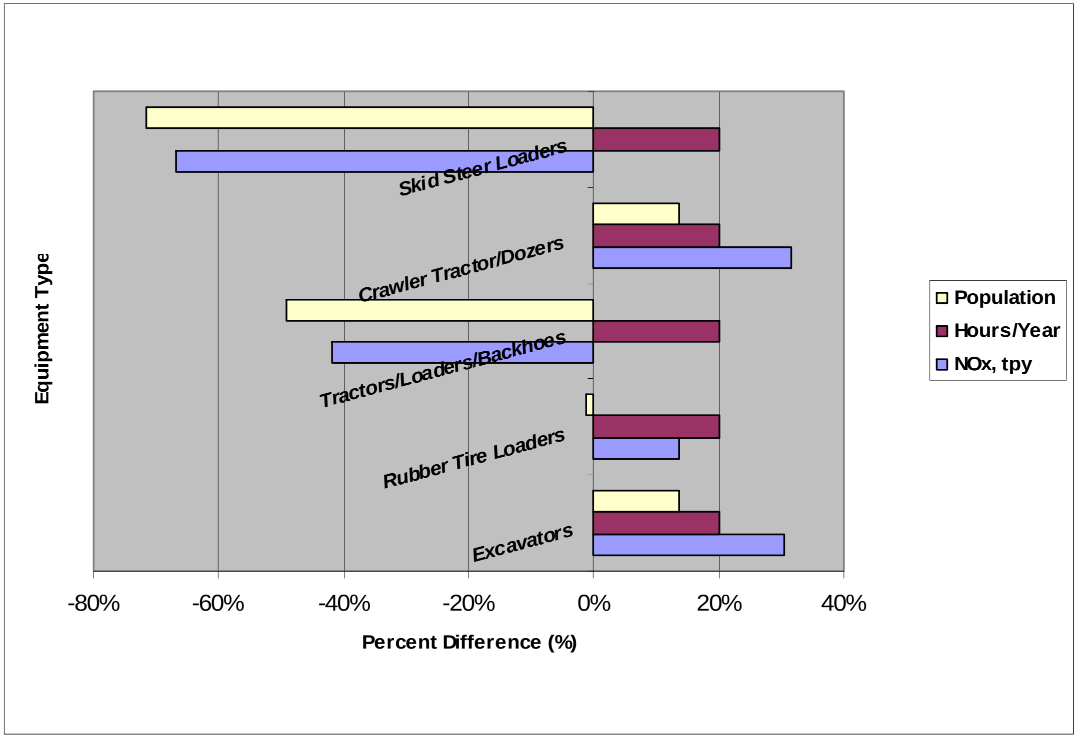


Exhibit E-5. Activity and Emissions Comparison (5-State Region-LADCO)

EQUIPMENT	Population		Hrs/Yr		Population * Hrs/Yr				NO_x, tpy		
	NR2004	LADCO	NR2004	LADCO	NR2004	LADCO	Difference (LADCO-NR2004)	% Difference (LADCO-NR2004)/ NR2004	NR2004	LADCO	% Difference
Skid Steer Loaders	76,837	27,944	818	982	62,852,416	27,441,094	-35,411,322	-56%	6,989	2,961	-58%
Crawler Tractor/Dozers	14,223	18,623	936	1,123	13,313,008	20,913,995	7,600,987	57%	15,577	23,632	52%
Tractors/Loaders/ Backhoes	49,374	30,650	1,135	1,362	56,039,943	41,745,941	-14,294,001	-26%	10,764	7,658	-29%
Rubber Tire Loaders	20,478	24,654	761	913	15,583,984	22,509,032	6,925,048	44%	17,795	24,644	38%
Excavators	18,507	25,307	1,092	1,310	20,209,752	33,151,616	12,941,864	64%	14,473	22,722	57%

Exhibit E-6. Percent Difference in Activity and NO_x Emissions (5-State Region-LADCO)

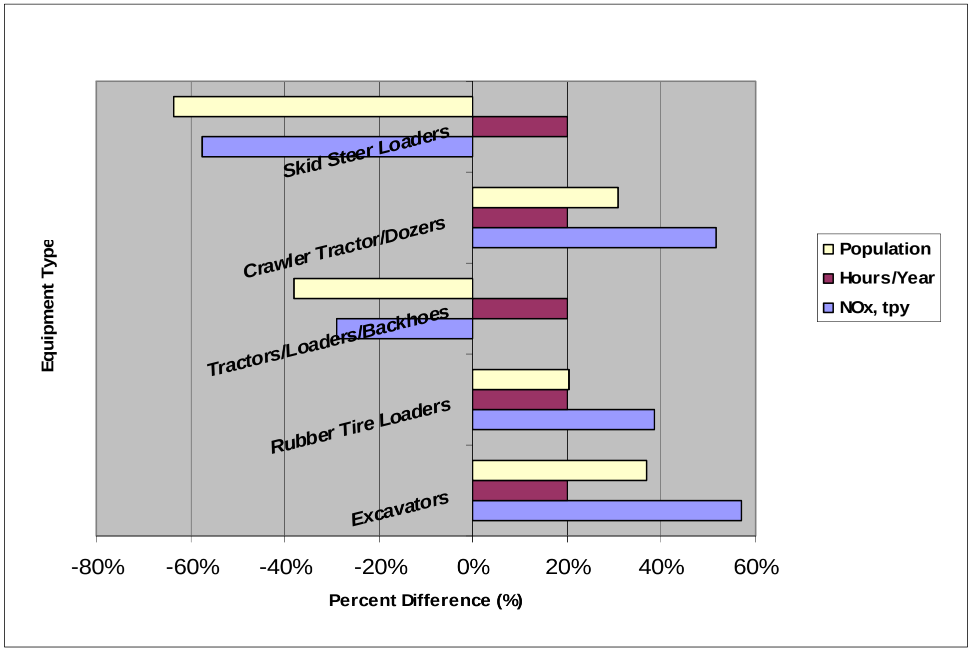


Exhibit E-7. Activity and Emissions Comparison (Clark County, Nevada)

	Population		Hrs/Yr		Population * Hrs/Yr				NO_x, tpy		
EQUIPMENT	NR2004	Clark Co	NR2004	Clark Co	NR2004	Clark Co	Difference (Clark Co-NR2004)	% Difference (Clark Co-NR2004)/ NR2004	NR2004	Clark Co	% Difference
Skid Steer Loaders	6,834	209	818	1,280	5,590,301	267,520	-5,322,781	-95%	622	27	-96%
Crawler Tractor/Dozers	1,265	73	936	1,186	1,184,086	86,578	-1,097,508	-93%	1,385	97	-93%
Tractors/Loaders/ Backhoes	4,392	330	1,135	1,812	4,984,451	597,960	-4,386,491	-88%	957	102	-89%
Rubber Tire Loaders	1,821	68	761	1,648	1,385,963	112,064	-1,273,899	-92%	1,582	108	-93%
Excavators	1,646	141	1,092	1,437	1,797,711	202,617	-1,595,094	-89%	1,288	136	-89%

Exhibit E-8. Percent Difference in Activity and NO_x Emissions (Clark County, Nevada)

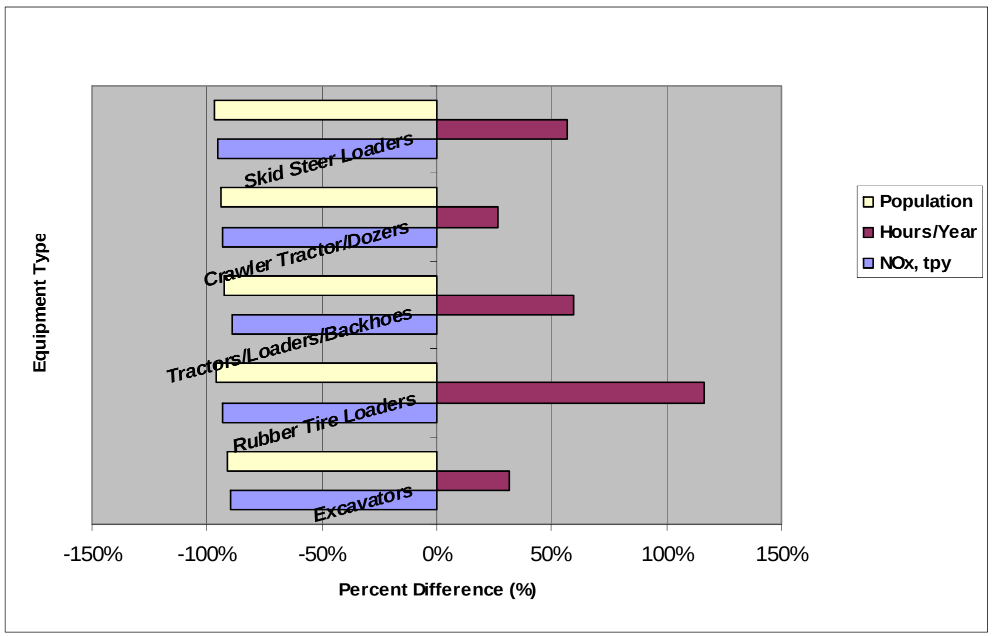
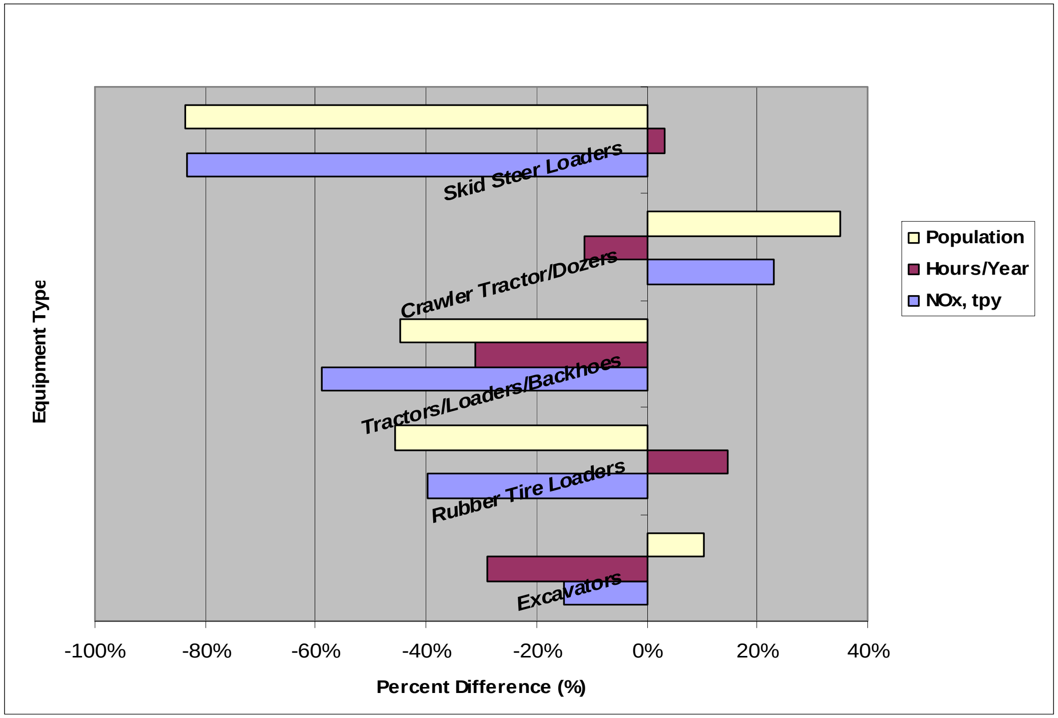


Exhibit E-9. Activity and Emissions Comparison (Houston-Galveston Study)

	Population		Hrs/Yr		Population * Hrs/Yr				NO_x, tpy		
EQUIPMENT	NR2004	Houston	NR2004	Houston	NR2004	Houston	Difference (Houston-NR2004)	% Difference (Houston-NR2004)/ NR2004	NR2004	Houston	% Difference
Skid Steer Loaders	8,129	1,328	818	845	6,649,485	1,122,160	-5,527,325	-83%	739	124	-83%
Crawler Tractor/Dozers	1,505	2,031	936	829	1,408,453	1,683,699	275,246	20%	1,648	2,025	23%
Tractors/Loaders/Backhoes	5,224	2,887	1,135	781	5,928,810	2,254,747	-3,674,063	-62%	1,139	467	-59%
Rubber Tire Loaders	2,167	1,179	761	872	1,648,734	1,028,088	-620,646	-38%	1,883	1,137	-40%
Excavators	1,958	2,161	1,092	777	2,138,069	1,679,097	-458,972	-21%	1,531	1,302	-15%

Exhibit E-10. Percent Difference in Activity and NO_x Emissions (Houston-Galveston)



CONCLUSIONS

For each study, the total equipment populations, usage, and NO_x emissions for all five SCCs are presented in Exhibit E-11. Percent differences in survey values compared to EPA defaults are shown in Exhibit E-12.

Note that for both LADCO studies, the overall NO_x emissions increase for all five SCCs, since increases for the three largest contributors (i.e., crawler tractor/dozers, rubber tire loaders, and excavators) outweigh decreases in the other two SCCs. For Clark County, large decreases in populations for all SCCs lead to overall NO_x emission decreases. Finally, for the Houston area study, declines in activity for four SCCs contribute to a NO_x emission decrease for all five SCCs combined.

The NONROAD model allocates national level equipment populations to counties based on surrogate indicators. The national populations are based on data provided by Power Systems Research (PSR), determined from engine manufacturer sales and usage surveys, and estimated engine life (EPA, 2002). Therefore, lower estimates for local equipment populations based on surveys may be offset by higher estimates for other areas if the national populations estimated by NONROAD are a reliable measure of the total in-use national engine populations. Hours of use values based on surveys may also be higher if survey respondents are providing these data for only the equipment they operate more frequently (i.e., it may not represent a fleet-wide average that should account for low-use equipment).

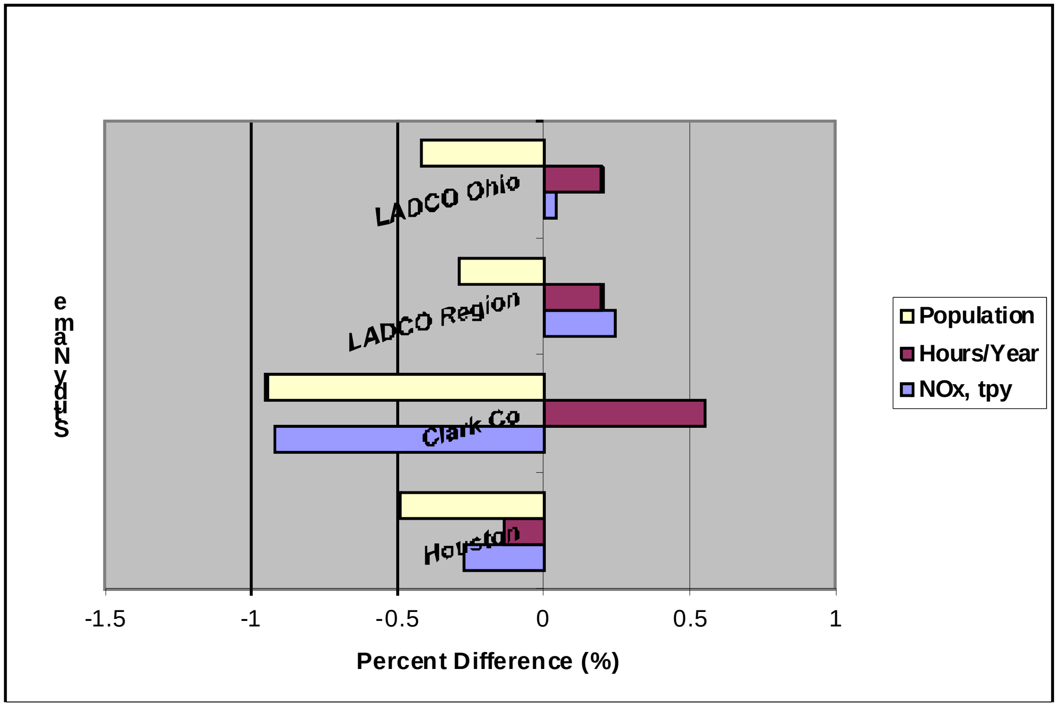
To obtain the actual equipment populations and the hours of use for a given geographic area, one would need to survey every equipment user. Because time and resources to survey each user may be prohibitive, random surveys of users are typically performed. To our knowledge, the survey results we have reviewed do not provide an estimate of survey error, so we cannot evaluate whether the differences are statistically significant.

Finally, to gauge the true impact on emissions, surveys should also focus on collecting statistically valid data for engine load factors and horsepower distributions, since these variables also affect emissions and may be intrinsically tied to local equipment populations and hours of use. One limitation of the survey data is that none of these studies collected sufficient data to replace default inputs for load factor or the horsepower distribution (and some did not request these data). For example, applications may operate more hours but they may also be operating at a lower average load factor, which would offset the increased usage.

Exhibit E-11. Comparison for Construction Studies

	Population		Hrs/Yr		Population * Hrs/Yr				NO_x, tpy		
	NR2004	LADCO	NR2004	LADCO	NR2004	Houston	Difference	% Difference	NR2004	LADCO	% Difference
LADCO Ohio	53,991	31,403	4,742	5690	256,025,772	178,682,596	-77,343,176	-30%	19,741	20,528	4%
LADCO Region	179,420	127,178	4,742	5690	850,808,639	723,645,010	-127,163,629	-15%	65,599	81,618	24%
Clark County	15,958	821	4,742	7363	75,673,969	6,045,023	-69,628,946	-92%	5,835	470	-92%
Houston	18,982	9,586	4,742	4104	90,011,733	39,340,944	-50,670,789	-56%	6,940	5,056	-27%

Exhibit E-12. Percent Difference in Activity and NO_x Emissions for Construction Studies



IMPACTS ON SECTION 812 INVENTORY

The impacts that revised activity inputs have on total off-road NO_x emission estimates vary depending on the relative contribution of area-specific NO_x emissions to the NO_x emissions for a given inventory area. The following examples using Clark County results illustrate this point.

The impact of incorporating Clark County survey-based NO_x emissions for the SCCs analyzed in the inventory for Clark County, for the State of Nevada, and for the entire United States, is shown in Exhibits E-12a, 13b, and 13c, respectively. The first column shows 2002 NO_x emissions using NR2004 default data, and the second column shows results using survey inputs. Clearly, the impact depends on the geographic area for which estimates are compared. The differences are most significant when considering local or State area inventories. However, when considering the impact these county-level differences have on the national SCC emissions inventory, the differences are relatively small.

Exhibit E-13a. Clark County Inventory Comparison

SCC	NR2004 NO_x, tpy	Clark Co NO_x, tpy	% Difference
2270002036	1,288	136	-89%
2270002060	1,582	108	-93%
2270002066	957	102	-89%
2270002069	1,385	97	-93%
2270002072	622	27	-96%

Exhibit E-13b. Nevada State-Level Inventory Comparison

	NR2004 NO_x, tpy	Clark Co NO_x, tpy	% Difference
2270002036	1,510	374	-75%
2270002060	1,855	401	-78%
2270002066	1,122	279	-75%
2270002069	1,624	353	-78%
2270002072	732	143	-80%

Exhibit E-13c. National Inventory Comparison

	NR2004 NO_x, tpy	Clark Co NO_x, tpy	% Difference
2270002036	98,295	97,159	-1%
2270002060	120,888	119,434	-1%
2270002066	73,134	72,291	-1%
2270002069	105,758	104,487	-1%
2270002072	47,271	46,682	-1%

REFERENCES

EPA, 2002: U.S. Environmental Protection Agency, *Nonroad Engine Population Estimates, NR-006b*, EPA420-P-02-004, Office of Transportation and Air Quality, Ann Arbor, MI. December 2002.

EPA, 2004: U.S. Environmental Protection Agency, Draft NONROAD2004, [computer software], Office of Transportation and Air Quality, Ann Arbor, MI. Available May 21, 2004 at: http://www.epa.gov/otaq/nonroadmdl.htm.

ERG, 2000: *Development of a Revised, Emissions Inventory for Construction Equipment in the Houston-Galveston Ozone Nonattainment Area, Final Report*, Prepared by Eastern Research Group, Inc., Prepared for The Houston Galveston Area Council and the Texas Natural Resources Conservation Commission, April 20, 2000.

MACTEC, 2003: *Inventory of Clark County-Wide Non-Road Engines, Draft Final Report*, Prepared by MACTEC Engineering and Consulting, Inc., Las Vegas, NV, Prepared for Clark County Department of Air Quality, Las Vegas, NV, October 2003.

Pechan, 2004: *LADCO Nonroad Emissions Inventory Project - Development Of Local Data For Construction And Agricultural Equipment Final Report*, Prepared for Lake Michigan Air Directors Consortium, Des Plaines, IL, Prepared by E.H. Pechan& Associates, Inc., Durham, NC, September 10, 2004.

APPENDIX F

CROSSWALK BETWEEN MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (MACT) CODES AND AEO ENERGY FORECAST VARIABLES

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
MACT CODE	**MACT DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
105	Stationary Reciprocating Internal Combustion Engines	INDC1801; INDC2101	Industrial	Mining and Refining	Distillate	National
0105-2	Stationary Reciprocating Internal Combustion Engines - Oil	INDC1801; INDC2101	Industrial	Mining and Refining	Distillate	National
0105-3	Stationary Reciprocating Internal Combustion Engines - Gas	INDC1803; INDC2103	Industrial	Mining and Refining	Natural Gas	National
107	Industrial/Commercial/ Institutional Boilers & Process Heaters	COMC1102; INDC2201	Commercial; Industrial		Delivered Energy	Regional
0107-1	Industrial/Commercial/Institutional Boilers & Process Heaters: Coal	COMC1101; INDC2213	Commercial; Industrial		Coal	Regional
0107-2	Industrial/Commercial/Institutional Boilers & Process Heaters: Natural Gas	COMC1107; INDC2206	Commercial; Industrial		Natural Gas	Regional
0107-3	Industrial/Commercial/Institutional Boilers & Process Heaters: Oil	COMC1103; INDC2202	Commercial; Industrial		Distillate	Regional
0107-4	Industrial/Commercial/Institutional Boilers & Process Heaters: Wood/Waste	COMC1109; INDC2210	Commercial; Industrial		Renewable Energy	Regional
108	Stationary Combustion Turbines	ELEC1209	Electric Generation		Total - Nuclear - Imports	Regional
0108-1	Stationary Combustion Turbines	ELEC1204	Electric Generation		Natural Gas	Regional
302	Coke Ovens: Charging, Top Side, and Door Leaks	INDC1602	Industrial	Iron and Steel	Metallurgical Coal	National
303	Coke Ovens: Pushing, Quenching, & Battery Stacks	INDC1602	Industrial	Iron and Steel	Metallurgical Coal	National
501	Oil & Natural Gas Production	PETP3101	Energy Production		Crude Oil and Natural Gas	Regional
502	Petroleum Refineries - Catalytic Cracking, Catalytic Reforming, & Sulfur Plant Units	PETS3001	Energy Production		Refined Petroleum Products	National
503	Petroleum Refineries - Other Sources Not Distinctly Listed	PETS3001	Energy Production		Refined Petroleum Products	National
504	Natural Gas Transmission & Storage	TOTC2504	Total Energy		Natural Gas	Regional
601	Gasoline Distribution (Stage I)	TRAN4001	Transportation		Motor Gasoline	Regional
1808-1	Utility Boilers: Coal	ELEC1208	Electric Generation		Steam Coal	Regional
1808-2	Utility Boilers: Natural Gas	ELEC1204	Electric Generation		Natural Gas	Regional
1808-3	Utility Boilers: Oil	ELEC1201	Electric Generation		Distillate	Regional

APPENDIX G

CROSSWALK BETWEEN SOURCE CLASSIFICATION CODES (SCCS) AND AEO ENERGY FORECAST VARIABLES

SCC	SCC DESCRIPTION	INDICATOR CODE(S)	ANNUAL ENERGY OUTLOOK 2005 VARIABLE SECTOR(S)	SUBSECTOR(S)	FUEL TYPE	GEOGRAPHIC RESOLUTION
10200060		INDC2201	Industrial	Total Industrial	Delivered Energy	Regional
10200101	External Combustion Boilers, Industrial, Anthracite Coal, Pulverized Coal	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200104	External Combustion Boilers, Industrial, Anthracite Coal, Traveling Grate (Overfeed) Stoker	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200107	External Combustion Boilers, Industrial, Anthracite Coal, Hand-fired	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200201	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Pulverized Coal: Wet Bottom	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200202	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Pulverized Coal: Dry Bottom	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200203	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Cyclone Furnace	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200204	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Spreader Stoker	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200205	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Overfeed Stoker	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200206	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Underfeed Stoker	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200210	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Overfeed Stoker **	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200212	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Pulverized Coal: Dry Bottom (Tangential)	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200213	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Wet Slurry	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200217	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Atmospheric Fluidized Bed Combustion: Bubbling Bed (Bituminous Coal)	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200219	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Cogeneration (Bituminous Coal)	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200221	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Pulverized Coal: Wet Bottom (Subbituminous Coal)	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200222	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Pulverized Coal: Dry Bottom (Subbituminous Coal)	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200223	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Cyclone Furnace (Subbituminous Coal)	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200224	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Spreader Stoker (Subbituminous Coal)	INDC2212	Industrial	Total Industrial	Steam Coal	Regional

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
10200225	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Traveling Grate (Overfeed) Stoker (Subbituminous Coal)	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200226	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Pulverized Coal: Dry Bottom Tangential (Subbituminous Coal)	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200229	External Combustion Boilers, Industrial, Bituminous/Subbituminous Coal, Cogeneration (Subbituminous Coal)	INDC2213	Industrial	Total Industrial	Total Coal	Regional
10200301	External Combustion Boilers, Industrial, Lignite, Pulverized Coal: Dry Bottom, Wall Fired	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200303	External Combustion Boilers, Industrial, Lignite, Cyclone Furnace	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200306	External Combustion Boilers, Industrial, Lignite, Spreader Stoker	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
10200307	External Combustion Boilers, Industrial, Lignite, Cogeneration	INDC2213	Industrial	Total Industrial	Total Coal	Regional
10200401	External Combustion Boilers, Industrial, Residual Oil, Grade 6 Oil	INDC2211	Industrial	Total Industrial	Residual	Regional
10200402	External Combustion Boilers, Industrial, Residual Oil, 10-100 Million Btu/hr **	INDC2211	Industrial	Total Industrial	Residual	Regional
10200403	External Combustion Boilers, Industrial, Residual Oil, < 10 Million Btu/hr **	INDC2211	Industrial	Total Industrial	Residual	Regional
10200404	External Combustion Boilers, Industrial, Residual Oil, Grade 5 Oil	INDC2211	Industrial	Total Industrial	Residual	Regional
10200405	External Combustion Boilers, Industrial, Residual Oil, Cogeneration	INDC2211	Industrial	Total Industrial	Residual	Regional
10200501	External Combustion Boilers, Industrial, Distillate Oil, Grades 1 and 2 Oil	INDC2202	Industrial	Total Industrial	Distillate	Regional
10200502	External Combustion Boilers, Industrial, Distillate Oil, 10-100 Million Btu/hr **	INDC2202	Industrial	Total Industrial	Distillate	Regional
10200503	External Combustion Boilers, Industrial, Distillate Oil, < 10 Million Btu/hr **	INDC2202	Industrial	Total Industrial	Distillate	Regional
10200504	External Combustion Boilers, Industrial, Distillate Oil, Grade 4 Oil	INDC2202	Industrial	Total Industrial	Distillate	Regional
10200505	External Combustion Boilers, Industrial, Distillate Oil, Cogeneration	INDC2202	Industrial	Total Industrial	Distillate	Regional
10200601	External Combustion Boilers, Industrial, Natural Gas, > 100 Million Btu/hr	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
10200602	External Combustion Boilers, Industrial, Natural Gas, 10-100 Million Btu/hr	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
10200603	External Combustion Boilers, Industrial, Natural Gas, < 10 Million Btu/hr	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
10200604	External Combustion Boilers, Industrial, Natural Gas, Cogeneration	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
10200699		INDC2206	Industrial	Total Industrial	Natural Gas	Regional
10200701	External Combustion Boilers, Industrial, Process Gas, Petroleum Refinery Gas	INDC2107	Industrial	Refining	Still Gas	National
10200704	External Combustion Boilers, Industrial, Process Gas, Blast Furnace Gas	INDC1602	Industrial	Iron and Steel	Metallurgical Coal	National
10200707	External Combustion Boilers, Industrial, Process Gas, Coke Oven Gas	INDC1602	Industrial	Iron and Steel	Metallurgical Coal	National
10200710	External Combustion Boilers, Industrial, Process Gas, Cogeneration	INDC2201	Industrial	Total Industrial	Delivered Energy	Regional
10200799	External Combustion Boilers, Industrial, Process Gas, Other: Specify in Comments	INDC2201	Industrial	Total Industrial	Delivered Energy	Regional

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
10200802	External Combustion Boilers, Industrial, Coke, All Boiler Sizes	INDC2207	Industrial	Total Industrial	Other Petroleum	Regional
10200804	External Combustion Boilers, Industrial, Coke, Cogeneration	INDC2207	Industrial	Total Industrial	Other Petroleum	Regional
10200901	External Combustion Boilers, Industrial, Wood/Bark Waste, Bark-fired Boiler	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
10200902	External Combustion Boilers, Industrial, Wood/Bark Waste, Wood/Bark-fired Boiler	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
10200903	External Combustion Boilers, Industrial, Wood/Bark Waste, Wood-fired Boiler - Wet Wood (>=20% moisture)	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
10200904	External Combustion Boilers, Industrial, Wood/Bark Waste, Bark-fired Boiler (< 50,000 Lb Steam) **	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
10200905	External Combustion Boilers, Industrial, Wood/Bark Waste, Wood/Bark-fired Boiler (< 50,000 Lb Steam) **	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
10200906	External Combustion Boilers, Industrial, Wood/Bark Waste, Wood-fired Boiler (< 50,000 Lb Steam) **	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
10200907	External Combustion Boilers, Industrial, Wood/Bark Waste, Wood Cogeneration	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
10201001	External Combustion Boilers, Industrial, Liquified Petroleum Gas (LPG), Butane	INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
10201002	External Combustion Boilers, Industrial, Liquified Petroleum Gas (LPG), Propane	INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
10201101	External Combustion Boilers, Industrial, Bagasse, All Boiler Sizes	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
10201201	External Combustion Boilers, Industrial, Solid Waste, Specify Waste Material in Comments	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
10201301	External Combustion Boilers, Industrial, Liquid Waste, Specify Waste Material in Comments	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
10201302	External Combustion Boilers, Industrial, Liquid Waste, Waste Oil	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
10201401	External Combustion Boilers, Industrial, CO Boiler, Natural Gas	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
10201402	External Combustion Boilers, Industrial, CO Boiler, Process Gas	INDC2201	Industrial	Total Industrial	Delivered Energy	Regional
10201404	External Combustion Boilers, Industrial, CO Boiler, Residual Oil	INDC2211	Industrial	Total Industrial	Residual	Regional
10299997		INDC2201	Industrial	Total Industrial	Delivered Energy	Regional

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10300101	External Combustion Boilers, Commercial/Institutional, Anthracite Coal, Pulverized Coal	COMC1101	Commercial		Coal	Regional
10300102	External Combustion Boilers, Commercial/Institutional, Anthracite Coal, Traveling Grate (Overfeed) Stoker	COMC1101	Commercial		Coal	Regional
10300103	External Combustion Boilers, Commercial/Institutional, Anthracite Coal, Hand-fired	COMC1101	Commercial		Coal	Regional
10300205	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Pulverized Coal: Wet Bottom (Bituminous Coal)	COMC1101	Commercial		Coal	Regional
10300206	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Pulverized Coal: Dry Bottom (Bituminous Coal)	COMC1101	Commercial		Coal	Regional
10300207	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Overfeed Stoker (Bituminous Coal)	COMC1101	Commercial		Coal	Regional
10300208	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Underfeed Stoker (Bituminous Coal)	COMC1101	Commercial		Coal	Regional
10300209	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Spreader Stoker (Bituminous Coal)	COMC1101	Commercial		Coal	Regional
10300211	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Overfeed Stoker **	COMC1101	Commercial		Coal	Regional
10300214	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Hand-fired (Bituminous Coal)	COMC1101	Commercial		Coal	Regional
10300216	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Pulverized Coal: Dry Bottom (Tangential) (Bituminous Coal)	COMC1101	Commercial		Coal	Regional
10300217	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Atmospheric Fluidized Bed Combustion: Bubbling Bed (Bituminous Coal)	COMC1101	Commercial		Coal	Regional
10300221	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Pulverized Coal: Wet Bottom (Subbituminous Coal)	COMC1101	Commercial		Coal	Regional
10300222	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Pulverized Coal: Dry Bottom (Subbituminous Coal)	COMC1101	Commercial		Coal	Regional
10300223	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Cyclone Furnace (Subbituminous Coal)	COMC1101	Commercial		Coal	Regional
10300224	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Spreader Stoker (Subbituminous Coal)	COMC1101	Commercial		Coal	Regional
10300225	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Traveling Grate (Overfeed) Stoker (Subbituminous Coal)	COMC1101	Commercial		Coal	Regional
10300226	External Combustion Boilers, Commercial/Institutional, Bituminous/Subbituminous Coal, Pulverized Coal: Dry Bottom Tangential (Subbituminous Coal)	COMC1101	Commercial		Coal	Regional
10300306	External Combustion Boilers, Commercial/Institutional, Lignite, Pulverized Coal: Dry Bottom, Tangential Fired	COMC1101	Commercial		Coal	Regional

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			SECTOR(S)	SUBSECTOR(S)	FUEL TYPE	GEOGRAPHIC RESOLUTION
10300309	External Combustion Boilers, Commercial/Institutional, Lignite, Spreader Stoker	COMC1101	Commercial		Coal	Regional
10300401	External Combustion Boilers, Commercial/Institutional, Residual Oil, Grade 6 Oil	COMC1110	Commercial		Residual	Regional
10300402	External Combustion Boilers, Commercial/Institutional, Residual Oil, 10-100 Million Btu/hr **	COMC1110	Commercial		Residual	Regional
10300403	External Combustion Boilers, Commercial/Institutional, Residual Oil, < 10 Million Btu/hr **	COMC1110	Commercial		Residual	Regional
10300404	External Combustion Boilers, Commercial/Institutional, Residual Oil, Grade 5 Oil	COMC1110	Commercial		Residual	Regional
10300501	External Combustion Boilers, Commercial/Institutional, Distillate Oil, Grades 1 and 2 Oil	COMC1103	Commercial		Distillate	Regional
10300502	External Combustion Boilers, Commercial/Institutional, Distillate Oil, 10-100 Million Btu/hr **	COMC1103	Commercial		Distillate	Regional
10300503	External Combustion Boilers, Commercial/Institutional, Distillate Oil, < 10 Million Btu/hr **	COMC1103	Commercial		Distillate	Regional
10300504	External Combustion Boilers, Commercial/Institutional, Distillate Oil, Grade 4 Oil	COMC1103	Commercial		Distillate	Regional
10300601	External Combustion Boilers, Commercial/Institutional, Natural Gas, > 100 Million Btu/hr	COMC1107	Commercial		Natural Gas	Regional
10300602	External Combustion Boilers, Commercial/Institutional, Natural Gas, 10-100 Million Btu/hr	COMC1107	Commercial		Natural Gas	Regional
10300603	External Combustion Boilers, Commercial/Institutional, Natural Gas, < 10 Million Btu/hr	COMC1107	Commercial		Natural Gas	Regional
10300701	External Combustion Boilers, Commercial/Institutional, Process Gas, POTW Digester Gas-fired Boiler	COMC1102	Commercial		Delivered Energy	Regional
10300799	External Combustion Boilers, Commercial/Institutional, Process Gas, Other Not Classified	COMC1102	Commercial		Delivered Energy	Regional
10300901	External Combustion Boilers, Commercial/Institutional, Wood/Bark Waste, Bark-fired Boiler	COMC1109	Commercial		Renewable Energy	Regional
10300902	External Combustion Boilers, Commercial/Institutional, Wood/Bark Waste, Wood/Bark-fired Boiler	COMC1109	Commercial		Renewable Energy	Regional
10300903	External Combustion Boilers, Commercial/Institutional, Wood/Bark Waste, Wood-fired Boiler - Wet Wood (>=20% moisture)	COMC1109	Commercial		Renewable Energy	Regional
10301001	External Combustion Boilers, Commercial/Institutional, Liquified Petroleum Gas (LPG), Butane	COMC1105	Commercial		Liquified Petroleum Gas	Regional
10301002	External Combustion Boilers, Commercial/Institutional, Liquified Petroleum Gas (LPG), Propane	COMC1105	Commercial		Liquified Petroleum Gas	Regional
10301201	External Combustion Boilers, Commercial/Institutional, Solid Waste, Specify Waste Material in Comments	COMC1109	Commercial		Renewable Energy	Regional

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10301202	External Combustion Boilers, Commercial/Institutional, Solid Waste, Refuse Derived Fuel	COMC1109	Commercial		Renewable Energy	Regional
10301301	External Combustion Boilers, Commercial/Institutional, Liquid Waste, Specify Waste Material in Comments	COMC1109	Commercial		Renewable Energy	Regional
10301302	External Combustion Boilers, Commercial/Institutional, Liquid Waste, Waste Oil	COMC1108	Commercial		Petroleum Subtotal	Regional
10500102	External Combustion Boilers, Space Heaters, Industrial, Coal **	INDC2213	Industrial	Total Industrial	Total Coal	Regional
10500105	External Combustion Boilers, Space Heaters, Industrial, Distillate Oil	INDC2202	Industrial	Total Industrial	Distillate	Regional
10500106	External Combustion Boilers, Space Heaters, Industrial, Natural Gas	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
10500110	External Combustion Boilers, Space Heaters, Industrial, Liquified Petroleum Gas (LPG)	INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
10500113	External Combustion Boilers, Space Heaters, Industrial, Waste Oil: Air Atomized Burner	INDC2207	Industrial	Total Industrial	Other Petroleum	Regional
10500205	External Combustion Boilers, Space Heaters, Commercial/Institutional, Distillate Oil	COMC1103	Commercial		Distillate	Regional
10500206	External Combustion Boilers, Space Heaters, Commercial/Institutional, Natural Gas	COMC1107	Commercial		Natural Gas	Regional
10500209	External Combustion Boilers, Space Heaters, Commercial/Institutional, Wood	COMC1109	Commercial		Renewable Energy	Regional
10500210	External Combustion Boilers, Space Heaters, Commercial/Institutional, Liquified Petroleum Gas (LPG)	COMC1105	Commercial		Liquified Petroleum Gas	Regional
10500213	External Combustion Boilers, Space Heaters, Commercial/Institutional, Waste Oil: Air Atomized Burner	COMC1108	Commercial		Petroleum Subtotal	Regional
10500214	External Combustion Boilers, Space Heaters, Commercial/Institutional, Waste Oil: Vaporizing Burner	COMC1108	Commercial		Petroleum Subtotal	Regional
20200101	Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Turbine	INDC2202	Industrial	Total Industrial	Distillate	Regional
20200102	Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating	INDC2202	Industrial	Total Industrial	Distillate	Regional
20200103	Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Turbine: Cogeneration	INDC2202	Industrial	Total Industrial	Distillate	Regional
20200104	Internal Combustion Engines, Industrial, Distillate Oil (Diesel), Reciprocating: Cogeneration	INDC2202	Industrial	Total Industrial	Distillate	Regional
20200201	Internal Combustion Engines, Industrial, Natural Gas, Turbine	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
20200202	Internal Combustion Engines, Industrial, Natural Gas, Reciprocating	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
20200203	Internal Combustion Engines, Industrial, Natural Gas, Turbine: Cogeneration	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
20200204	Internal Combustion Engines, Industrial, Natural Gas, Reciprocating: Cogeneration	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
20200301	Internal Combustion Engines, Industrial, Gasoline, Reciprocating	INDC2205	Industrial	Total Industrial	Motor Gasoline	Regional
20200401	Internal Combustion Engines, Industrial, Large Bore Engine, Diesel	INDC2202	Industrial	Total Industrial	Distillate	Regional

SCC	SCC DESCRIPTION	INDICATOR CODE(S)	ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
			SECTOR(S)	SUBSECTOR(S)	FUEL TYPE	GEOGRAPHIC RESOLUTION
20200402	Internal Combustion Engines, Industrial, Large Bore Engine, Dual Fuel (Oil/Gas)	INDC2209	Industrial	Total Industrial	Petroleum Subtotal & Natural Gas	Regional
20200403	Internal Combustion Engines, Industrial, Large Bore Engine, Cogeneration: Dual Fuel	INDC2209	Industrial	Total Industrial	Petroleum Subtotal & Natural Gas	Regional
20200501	Internal Combustion Engines, Industrial, Residual/Crude Oil, Reciprocating	INDC2211	Industrial	Total Industrial	Residual	Regional
20200901	Internal Combustion Engines, Industrial, Kerosene/Naphtha (Jet Fuel), Turbine	INDC2207	Industrial	Total Industrial	Other Petroleum	Regional
20200902	Internal Combustion Engines, Industrial, Kerosene/Naphtha (Jet Fuel), Reciprocating	INDC2207	Industrial	Total Industrial	Other Petroleum	Regional
20201001	Internal Combustion Engines, Industrial, Liquified Petroleum Gas (LPG), Propane: Reciprocating	INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
20201002	Internal Combustion Engines, Industrial, Liquified Petroleum Gas (LPG), Butane: Reciprocating	INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
20201003		INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
20201101		INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
20300101	Internal Combustion Engines, Commercial/Institutional, Distillate Oil (Diesel), Reciprocating	COMC1103	Commercial		Distillate	Regional
20300102	Internal Combustion Engines, Commercial/Institutional, Distillate Oil (Diesel), Turbine	COMC1103	Commercial		Distillate	Regional
20300201	Internal Combustion Engines, Commercial/Institutional, Natural Gas, Reciprocating	COMC1107	Commercial		Natural Gas	Regional
20300202	Internal Combustion Engines, Commercial/Institutional, Natural Gas, Turbine	COMC1107	Commercial		Natural Gas	Regional
20300203	Internal Combustion Engines, Commercial/Institutional, Natural Gas, Turbine: Cogeneration	COMC1107	Commercial		Natural Gas	Regional
20300204	Internal Combustion Engines, Commercial/Institutional, Natural Gas, Cogeneration	COMC1107	Commercial		Natural Gas	Regional
20300301	Internal Combustion Engines, Commercial/Institutional, Gasoline, Reciprocating	COMC1106	Commercial		Motor Gasoline	Regional
20300702	Internal Combustion Engines, Commercial/Institutional, Digester Gas, Reciprocating: POTW Digester Gas	COMC1109	Commercial		Renewable Energy	Regional
20300902		COMC1104	Commercial		Kerosene	Regional
20301001	Internal Combustion Engines, Commercial/Institutional, Liquified Petroleum Gas (LPG), Propane: Reciprocating	COMC1105	Commercial		Liquified Petroleum Gas	Regional
28888801	Internal Combustion Engines, Fugitive Emissions, Other Not Classified, Specify in Comments	TTRC2601	Total Energy - Transportation		Distillate Fuel	Regional

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28888802	Internal Combustion Engines, Fugitive Emissions, Other Not Classified, Specify in Comments	TTRC2603	Total Energy - Transportation		Total	Regional
28888803	Internal Combustion Engines, Fugitive Emissions, Other Not Classified, Specify in Comments	TTRC2603	Total Energy - Transportation		Total	Regional
30190001	Industrial Processes, Chemical Manufacturing, Fuel Fired Equipment, Distillate Oil (No. 2): Process Heaters	INDC1301	Industrial	Bulk Chemicals	Heat and Power-Distillate	National
30190002	Industrial Processes, Chemical Manufacturing, Fuel Fired Equipment, Residual Oil: Process Heaters	INDC1303	Industrial	Bulk Chemicals	Heat and Power-Residual	National
30190003	Industrial Processes, Chemical Manufacturing, Fuel Fired Equipment, Natural Gas: Process Heaters	INDC1302	Industrial	Bulk Chemicals	Heat and Power-Natural Gas	National
30190004	Industrial Processes, Chemical Manufacturing, Fuel Fired Equipment, Process Gas: Process Heaters	INDC1304	Industrial	Bulk Chemicals	Total Heat and Power	National
30190011	Industrial Processes, Chemical Manufacturing, Fuel Fired Equipment, Distillate Oil (No. 2): Incinerators	INDC1301	Industrial	Bulk Chemicals	Heat and Power-Distillate	National
30190012	Industrial Processes, Chemical Manufacturing, Fuel Fired Equipment, Residual Oil: Incinerators	INDC1303	Industrial	Bulk Chemicals	Heat and Power-Residual	National
30190013	Industrial Processes, Chemical Manufacturing, Fuel Fired Equipment, Natural Gas: Incinerators	INDC1302	Industrial	Bulk Chemicals	Heat and Power-Natural Gas	National
30190014	Industrial Processes, Chemical Manufacturing, Fuel Fired Equipment, Process Gas: Incinerators	INDC1304	Industrial	Bulk Chemicals	Total Heat and Power	National
30190023	Industrial Processes, Chemical Manufacturing, Fuel Fired Equipment, Natural Gas: Flares	INDC1302	Industrial	Bulk Chemicals	Heat and Power-Natural Gas	National
30190099	Industrial Processes, Chemical Manufacturing, Fuel Fired Equipment, Specify in Comments Field	INDC1304	Industrial	Bulk Chemicals	Total Heat and Power	National
30290001	Industrial Processes, Food and Agriculture, Fuel Fired Equipment, Distillate Oil (No. 2): Process Heaters	INDC1501	Industrial	Food	Distillate	National
30290002	Industrial Processes, Food and Agriculture, Fuel Fired Equipment, Residual Oil: Process Heaters	INDC1504	Industrial	Food	Residual	National
30290003	Industrial Processes, Food and Agriculture, Fuel Fired Equipment, Natural Gas: Process Heaters	INDC1503	Industrial	Food	Natural Gas	National
30390001	Industrial Processes, Primary Metal Production, Fuel Fired Equipment, Distillate Oil (No. 2): Process Heaters	INDC1601	Industrial	Iron and Steel	Distillate	National
30390003	Industrial Processes, Primary Metal Production, Fuel Fired Equipment, Natural Gas: Process Heaters	INDC1603	Industrial	Iron and Steel	Natural Gas	National

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
30390004	Industrial Processes, Primary Metal Production, Fuel Fired Equipment, Process Gas: Process Heaters	INDC1606	Industrial	Iron and Steel	Total	National
30390013	Industrial Processes, Primary Metal Production, Fuel Fired Equipment, Natural Gas: Incinerators	INDC1603	Industrial	Iron and Steel	Natural Gas	National
30390014	Industrial Processes, Primary Metal Production, Fuel Fired Equipment, Process Gas: Incinerators	INDC1606	Industrial	Iron and Steel	Total	National
30390024	Industrial Processes, Primary Metal Production, Fuel Fired Equipment, Process Gas: Flares	INDC1606	Industrial	Iron and Steel	Total	National
30400406	Industrial Processes, Secondary Metal Production, Lead, Pot Furnace Heater: Distillate Oil	INDC1901	Industrial	Other Manufacturing	Distillate	National
30400407	Industrial Processes, Secondary Metal Production, Lead, Pot Furnace Heater: Natural Gas	INDC1903	Industrial	Other Manufacturing	Natural Gas	National
30490001	Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Distillate Oil (No. 2): Process Heaters	INDC1901	Industrial	Other Manufacturing	Distillate	National
30490003	Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Natural Gas: Process Heaters	INDC1903	Industrial	Other Manufacturing	Natural Gas	National
30490004	Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Process Gas: Process Heaters	INDC1908	Industrial	Other Manufacturing	Total	National
30490013	Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Natural Gas: Incinerators	INDC1903	Industrial	Other Manufacturing	Natural Gas	National
30490023	Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Natural Gas: Flares	INDC1903	Industrial	Other Manufacturing	Natural Gas	National
30490024	Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Process Gas: Flares	INDC1908	Industrial	Other Manufacturing	Total	National
30490031	Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Distillate Oil (No. 2): Furnaces	INDC1901	Industrial	Other Manufacturing	Distillate	National
30490033	Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Natural Gas: Furnaces	INDC1903	Industrial	Other Manufacturing	Natural Gas	National
30490034	Industrial Processes, Secondary Metal Production, Fuel Fired Equipment, Process Gas: Furnaces	INDC1908	Industrial	Other Manufacturing	Total	National
30500206	Industrial Processes, Mineral Products, Asphalt Concrete, Asphalt Heater: Natural Gas	INDC2103	Industrial	Refining	Natural Gas	National
30500207	Industrial Processes, Mineral Products, Asphalt Concrete, Asphalt Heater: Residual Oil	INDC2106	Industrial	Refining	Residual	National
30500208	Industrial Processes, Mineral Products, Asphalt Concrete, Asphalt Heater: Distillate Oil	INDC2101	Industrial	Refining	Distillate	National

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30500209	Industrial Processes, Mineral Products, Asphalt Concrete, Asphalt Heater: LPG	INDC2102	Industrial	Refining	Liquified Petroleum Gas	National
30500210	Industrial Processes, Mineral Products, Asphalt Concrete, Asphalt Heater: Waste Oil	INDC2104	Industrial	Refining	Other Petroleum	National
30590001	Industrial Processes, Mineral Products, Fuel Fired Equipment, Distillate Oil (No. 2): Process Heaters	INDC1801	Industrial	Mining	Distillate	National
30590002	Industrial Processes, Mineral Products, Fuel Fired Equipment, Residual Oil: Process Heaters	INDC1805	Industrial	Mining	Residual	National
30590003	Industrial Processes, Mineral Products, Fuel Fired Equipment, Natural Gas: Process Heaters	INDC1803	Industrial	Mining	Natural Gas	National
30590013	Industrial Processes, Mineral Products, Fuel Fired Equipment, Natural Gas: Incinerators	INDC1803	Industrial	Mining	Natural Gas	National
30590023	Industrial Processes, Mineral Products, Fuel Fired Equipment, Natural Gas: Flares	INDC1803	Industrial	Mining	Natural Gas	National
30600101	Industrial Processes, Petroleum Industry, Process Heaters, Oil-fired **	INDC2105	Industrial	Refining	Petroleum Subtotal	National
30600102	Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired **	INDC2103	Industrial	Refining	Natural Gas	National
30600103	Industrial Processes, Petroleum Industry, Process Heaters, Oil-fired	INDC2105	Industrial	Refining	Petroleum Subtotal	National
30600104	Industrial Processes, Petroleum Industry, Process Heaters, Gas-fired	INDC2103	Industrial	Refining	Natural Gas	National
30600105	Industrial Processes, Petroleum Industry, Process Heaters, Natural Gas-fired	INDC2103	Industrial	Refining	Natural Gas	National
30600106	Industrial Processes, Petroleum Industry, Process Heaters, Process Gas-fired	INDC2107	Industrial	Refining	Still Gas	National
30600107	Industrial Processes, Petroleum Industry, Process Heaters, LPG-fired	INDC2102	Industrial	Refining	Liquified Petroleum Gas	National
30600111	Industrial Processes, Petroleum Industry, Process Heaters, Oil-fired (No. 6 Oil) > 100 Million Btu Capacity	INDC2106	Industrial	Refining	Residual	National
30600197		INDC2108	Industrial	Refining	Total	National
30600199	Industrial Processes, Petroleum Industry, Process Heaters, Other Not Classified	INDC2108	Industrial	Refining	Total	National
30600201	Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Fluid Catalytic Cracking Unit	PETS3001	Energy Production		Refined Petroleum Products	National
30600202	Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Catalyst Handling System	PETS3001	Energy Production		Refined Petroleum Products	National
30600204		PETS3001	Energy Production		Refined Petroleum Products	National

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30600301	Industrial Processes, Petroleum Industry, Catalytic Cracking Units, Thermal Catalytic Cracking Unit	PETS3001	Energy Production		Refined Petroleum Products	National
30600401	Industrial Processes, Petroleum Industry, Blowdown Systems, Blowdown System with Vapor Recovery System with Flaring	PETS3001	Energy Production		Refined Petroleum Products	National
30600402	Industrial Processes, Petroleum Industry, Blowdown Systems, Blowdown System w/o Controls	PETS3001	Energy Production		Refined Petroleum Products	National
30600503	Industrial Processes, Petroleum Industry, Wastewater Treatment, Process Drains and Wastewater Separators	PETS3001	Energy Production		Refined Petroleum Products	National
30600504	Industrial Processes, Petroleum Industry, Wastewater Treatment, Process Drains and Wastewater Separators	PETS3001	Energy Production		Refined Petroleum Products	National
30600505	Industrial Processes, Petroleum Industry, Wastewater Treatment, Wastewater Treatment w/o Separator	PETS3001	Energy Production		Refined Petroleum Products	National
30600506	Industrial Processes, Petroleum Industry, Wastewater Treatment, Wastewater Treatment w/o Separator	PETS3001	Energy Production		Refined Petroleum Products	National
30600508	Industrial Processes, Petroleum Industry, Wastewater Treatment, Oil/Water Separator	PETS3001	Energy Production		Refined Petroleum Products	National
30600514	Industrial Processes, Petroleum Industry, Wastewater Treatment, Petroleum Refinery Wastewater System: Junction Box	PETS3001	Energy Production		Refined Petroleum Products	National
30600516	Industrial Processes, Petroleum Industry, Wastewater Treatment, Petroleum Refinery Wastewater System: Aerated Impoundment	PETS3001	Energy Production		Refined Petroleum Products	National
30600517	Industrial Processes, Petroleum Industry, Wastewater Treatment, Petroleum Refinery Wastewater System: Non-aerated Impoundment	PETS3001	Energy Production		Refined Petroleum Products	National
30600518	Industrial Processes, Petroleum Industry, Wastewater Treatment, Petroleum Refinery Wastewater System: Weir	PETS3001	Energy Production		Refined Petroleum Products	National

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
30600519	Industrial Processes, Petroleum Industry, Wastewater Treatment, Petroleum Refinery Wastewater System: Activated Sludge Impoundment	PETS3001	Energy Production		Refined Petroleum Products	National
30600520	Industrial Processes, Petroleum Industry, Wastewater Treatment, Petroleum Refinery Wastewater System: Clarifier	PETS3001	Energy Production		Refined Petroleum Products	National
30600602	Industrial Processes, Petroleum Industry, Vacuum Distillate Column Condensors, Vacuum Distillation Column Condenser	PETS3001	Energy Production		Refined Petroleum Products	National
30600603	Industrial Processes, Petroleum Industry, Vacuum Distillate Column Condensors, Vacuum Distillation Column Condenser	PETS3001	Energy Production		Refined Petroleum Products	National
30600701	Industrial Processes, Petroleum Industry, Cooling Towers, Cooling Towers	PETS3001	Energy Production		Refined Petroleum Products	National
30600702	Industrial Processes, Petroleum Industry, Cooling Towers, Cooling Towers	PETS3001	Energy Production		Refined Petroleum Products	National
30600801	Industrial Processes, Petroleum Industry, Fugitive Emissions, Pipeline Valves and Flanges	PETS3001	Energy Production		Refined Petroleum Products	National
30600802	Industrial Processes, Petroleum Industry, Fugitive Emissions, Vessel Relief Valves	PETS3001	Energy Production		Refined Petroleum Products	National
30600803	Industrial Processes, Petroleum Industry, Fugitive Emissions, Pump Seals w/o Controls	PETS3001	Energy Production		Refined Petroleum Products	National
30600804	Industrial Processes, Petroleum Industry, Fugitive Emissions, Compressor Seals	PETS3001	Energy Production		Refined Petroleum Products	National
30600805	Industrial Processes, Petroleum Industry, Fugitive Emissions, Miscellaneous: Sampling/Non-Asphalt Blowing/Purging/etc.	PETS3001	Energy Production		Refined Petroleum Products	National
30600806	Industrial Processes, Petroleum Industry, Fugitive Emissions, Pump Seals with Controls	PETS3001	Energy Production		Refined Petroleum Products	National

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
30600807	Industrial Processes, Petroleum Industry, Fugitive Emissions, Blind Changing	PETS3001	Energy Production		Refined Petroleum Products	National
30600811	Industrial Processes, Petroleum Industry, Fugitive Emissions, Pipeline Valves: Gas Streams	PETS3001	Energy Production		Refined Petroleum Products	National
30600812	Industrial Processes, Petroleum Industry, Fugitive Emissions, Pipeline Valves: Light Liquid/Gas Streams	PETS3001	Energy Production		Refined Petroleum Products	National
30600813	Industrial Processes, Petroleum Industry, Fugitive Emissions, Pipeline Valves: Heavy Liquid Streams	PETS3001	Energy Production		Refined Petroleum Products	National
30600814	Industrial Processes, Petroleum Industry, Fugitive Emissions, Pipeline Valves: Hydrogen Streams	PETS3001	Energy Production		Refined Petroleum Products	National
30600815	Industrial Processes, Petroleum Industry, Fugitive Emissions, Open-ended Valves: All Streams	PETS3001	Energy Production		Refined Petroleum Products	National
30600816	Industrial Processes, Petroleum Industry, Fugitive Emissions, Flanges: All Streams	PETS3001	Energy Production		Refined Petroleum Products	National
30600817	Industrial Processes, Petroleum Industry, Fugitive Emissions, Pump Seals: Light Liquid/Gas Streams	PETS3001	Energy Production		Refined Petroleum Products	National
30600818	Industrial Processes, Petroleum Industry, Fugitive Emissions, Pump Seals: Heavy Liquid Streams	PETS3001	Energy Production		Refined Petroleum Products	National
30600819	Industrial Processes, Petroleum Industry, Fugitive Emissions, Compressor Seals: Gas Streams	PETS3001	Energy Production		Refined Petroleum Products	National
30600820	Industrial Processes, Petroleum Industry, Fugitive Emissions, Compressor Seals: Heavy Liquid Streams	PETS3001	Energy Production		Refined Petroleum Products	National
30600821	Industrial Processes, Petroleum Industry, Fugitive Emissions, Drains: All Streams	PETS3001	Energy Production		Refined Petroleum Products	National

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SCC	SCC DESCRIPTION	INDICATOR CODE(S)	SECTOR(S)	SUBSECTOR(S)	FUEL TYPE	GEOGRAPHIC RESOLUTION
30600822	Industrial Processes, Petroleum Industry, Fugitive Emissions, Vessel Relief Valves: All Streams	PETS3001	Energy Production		Refined Petroleum Products	National
30600901	Industrial Processes, Petroleum Industry, Flares, Distillate Oil	INDC2101	Industrial	Refining	Distillate	National
30600903	Industrial Processes, Petroleum Industry, Flares, Natural Gas	INDC2103	Industrial	Refining	Natural Gas	National
30600904	Industrial Processes, Petroleum Industry, Flares, Process Gas	INDC2107	Industrial	Refining	Still Gas	National
30600905	Industrial Processes, Petroleum Industry, Flares, Liquified Petroleum Gas	INDC2102	Industrial	Refining	Liquified Petroleum Gas	National
30600906	Industrial Processes, Petroleum Industry, Flares, Hydrogen Sulfide	INDC2108	Industrial	Refining	Total	National
30600999	Industrial Processes, Petroleum Industry, Flares, Not Classified **	INDC2108	Industrial	Refining	Total	National
30601001	Industrial Processes, Petroleum Industry, Sludge Converter, General	PETS3001	Energy Production		Refined Petroleum Products	National
30601101	Industrial Processes, Petroleum Industry, Asphalt Blowing, General	PETS3001	Energy Production		Refined Petroleum Products	National
30601201	Industrial Processes, Petroleum Industry, Fluid Coking Units, General	PETS3001	Energy Production		Refined Petroleum Products	National
30601401	Industrial Processes, Petroleum Industry, Petroleum Coke Calcining, Coke Calciner	PETS3001	Energy Production		Refined Petroleum Products	National
30601601	Industrial Processes, Petroleum Industry, Catalytic Reforming Unit, General	PETS3001	Energy Production		Refined Petroleum Products	National
30603301	Industrial Processes, Petroleum Industry, Desulfurization, Sulfur Recovery Unit	PETS3001	Energy Production		Refined Petroleum Products	National
30609901	Industrial Processes, Petroleum Industry, Incinerators, Distillate Oil (No. 2)	INDC2101	Industrial	Refining	Distillate	National
30609902	Industrial Processes, Petroleum Industry, Incinerators, Residual Oil	INDC2106	Industrial	Refining	Residual	National
30609903	Industrial Processes, Petroleum Industry, Incinerators, Natural Gas	INDC2103	Industrial	Refining	Natural Gas	National
30609904	Industrial Processes, Petroleum Industry, Incinerators, Process Gas	INDC2108	Industrial	Refining	Total	National
30609999		INDC2108	Industrial	Refining	Total	National
30610001	Industrial Processes, Petroleum Industry, Lube Oil Refining, General	PETS3001	Energy Production		Refined Petroleum Products	National

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
30688801	Industrial Processes, Petroleum Industry, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
30688802	Industrial Processes, Petroleum Industry, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
30688803	Industrial Processes, Petroleum Industry, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
30688804	Industrial Processes, Petroleum Industry, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
30688805	Industrial Processes, Petroleum Industry, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
30699996		PETS3001	Energy Production		Refined Petroleum Products	National
30699998	Industrial Processes, Petroleum Industry, Petroleum Products - Not Classified, Not Classified **	PETS3001	Energy Production		Refined Petroleum Products	National
30699999	Industrial Processes, Petroleum Industry, Petroleum Products - Not Classified, Not Classified **	PETS3001	Energy Production		Refined Petroleum Products	National
30790001	Industrial Processes, Pulp and Paper and Wood Products, Fuel Fired Equipment, Distillate Oil (No. 2): Process Heaters	INDC2001	Industrial	Paper	Distillate	National
30790002	Industrial Processes, Pulp and Paper and Wood Products, Fuel Fired Equipment, Residual Oil: Process Heaters	INDC2003	Industrial	Paper	Residual	National
30790003	Industrial Processes, Pulp and Paper and Wood Products, Fuel Fired Equipment, Natural Gas: Process Heaters	INDC2002	Industrial	Paper	Natural Gas	National
30790013	Industrial Processes, Pulp and Paper and Wood Products, Fuel Fired Equipment, Natural Gas: Incinerators	INDC2002	Industrial	Paper	Natural Gas	National
30890003	Industrial Processes, Rubber and Miscellaneous Plastics Products, Fuel Fired Equipment, Natural Gas: Process Heaters	INDC1903	Industrial	Other Manufacturing	Natural Gas	National
30890013	Industrial Processes, Rubber and Miscellaneous Plastics Products, Fuel Fired Equipment, Natural Gas: Incinerators	INDC1903	Industrial	Other Manufacturing	Natural Gas	National
30890023	Industrial Processes, Rubber and Miscellaneous Plastics Products, Fuel Fired Equipment, Natural Gas: Flares	INDC1903	Industrial	Other Manufacturing	Natural Gas	National

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
30990001	Industrial Processes, Fabricated Metal Products, Fuel Fired Equipment, Distillate Oil (No. 2): Process Heaters	INDC1701	Industrial	Metals-Based Durables	Distillate	National
30990002	Industrial Processes, Fabricated Metal Products, Fuel Fired Equipment, Residual Oil: Process Heaters	INDC1703	Industrial	Metals-Based Durables	Residual	National
30990003	Industrial Processes, Fabricated Metal Products, Fuel Fired Equipment, Natural Gas: Process Heaters	INDC1702	Industrial	Metals-Based Durables	Natural Gas	National
30990013	Industrial Processes, Fabricated Metal Products, Fuel Fired Equipment, Natural Gas: Incinerators	INDC1702	Industrial	Metals-Based Durables	Natural Gas	National
30990023	Industrial Processes, Fabricated Metal Products, Fuel Fired Equipment, Natural Gas: Flares	INDC1702	Industrial	Metals-Based Durables	Natural Gas	National
31000101	Industrial Processes, Oil and Gas Production, Crude Oil Production, Complete Well: Fugitive Emissions	PETP3106	Energy Production		Crude Oil	Regional
31000102	Industrial Processes, Oil and Gas Production, Crude Oil Production, Miscellaneous Well: General	PETP3106	Energy Production		Crude Oil	Regional
31000103	Industrial Processes, Oil and Gas Production, Crude Oil Production, Wells: Rod Pumps	PETP3106	Energy Production		Crude Oil	Regional
31000104	Industrial Processes, Oil and Gas Production, Crude Oil Production, Crude Oil Sumps	PETP3106	Energy Production		Crude Oil	Regional
31000105	Industrial Processes, Oil and Gas Production, Crude Oil Production, Crude Oil Pits	PETP3106	Energy Production		Crude Oil	Regional
31000106	Industrial Processes, Oil and Gas Production, Crude Oil Production, Enhanced Wells, Water Reinjection	PETP3106	Energy Production		Crude Oil	Regional
31000107	Industrial Processes, Oil and Gas Production, Crude Oil Production, Oil/Gas/Water/Separation	PETP3106	Energy Production		Crude Oil	Regional
31000199	Industrial Processes, Oil and Gas Production, Crude Oil Production, Processing Operations: Not Classified	PETP3106	Energy Production		Crude Oil	Regional
31000201	Industrial Processes, Oil and Gas Production, Natural Gas Production, Gas Sweetening: Amine Process	PETP3104	Energy Production		Natural Gas	Regional
31000202	Industrial Processes, Oil and Gas Production, Natural Gas Production, Gas Stripping Operations	PETP3104	Energy Production		Natural Gas	Regional
31000203	Industrial Processes, Oil and Gas Production, Natural Gas Production, Compressors	PETP3104	Energy Production		Natural Gas	Regional
31000204	Industrial Processes, Oil and Gas Production, Natural Gas Production, Wells	PETP3104	Energy Production		Natural Gas	Regional
31000205	Industrial Processes, Oil and Gas Production, Natural Gas Production, Flares	PETP3104	Energy Production		Natural Gas	Regional

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
31000206	Industrial Processes, Oil and Gas Production, Natural Gas Production, Gas Lift	PETP3104	Energy Production		Natural Gas	Regional
31000207	Industrial Processes, Oil and Gas Production, Natural Gas Production, Valves: Fugitive Emissions	PETP3104	Energy Production		Natural Gas	Regional
31000208	Industrial Processes, Oil and Gas Production, Natural Gas Production, Sulfur Recovery Unit	PETP3104	Energy Production		Natural Gas	Regional
31000299	Industrial Processes, Oil and Gas Production, Natural Gas Production, Other Not Classified	PETP3104	Energy Production		Natural Gas	Regional
31000401	Industrial Processes, Oil and Gas Production, Process Heaters, Distillate Oil (No. 2)	INDC1801	Industrial	Mining	Distillate	National
31000402	Industrial Processes, Oil and Gas Production, Process Heaters, Residual Oil	INDC1805	Industrial	Mining	Residual	National
31000403	Industrial Processes, Oil and Gas Production, Process Heaters, Crude Oil	INDC1804	Industrial	Mining	Other Petroleum	National
31000404	Industrial Processes, Oil and Gas Production, Process Heaters, Natural Gas	INDC1803	Industrial	Mining	Natural Gas	National
31000405	Industrial Processes, Oil and Gas Production, Process Heaters, Process Gas	PETP3101	Energy Production		Crude Oil and Natural Gas	Regional
31000411	Industrial Processes, Oil and Gas Production, Process Heaters, Distillate Oil (No. 2): Steam Generators	INDC1801	Industrial	Mining	Distillate	National
31000412	Industrial Processes, Oil and Gas Production, Process Heaters, Residual Oil: Steam Generators	INDC1805	Industrial	Mining	Residual	National
31000413	Industrial Processes, Oil and Gas Production, Process Heaters, Crude Oil: Steam Generators	INDC1804	Industrial	Mining	Other Petroleum	National
31000414	Industrial Processes, Oil and Gas Production, Process Heaters, Natural Gas: Steam Generators	INDC1803	Industrial	Mining	Natural Gas	National
31000415	Industrial Processes, Oil and Gas Production, Process Heaters, Process Gas: Steam Generators	PETP3101	Energy Production		Crude Oil and Natural Gas	Regional
31088801	Industrial Processes, Oil and Gas Production, Fugitive Emissions, Specify in Comments Field	PETP3101	Energy Production		Crude Oil and Natural Gas	Regional
31088802	Industrial Processes, Oil and Gas Production, Fugitive Emissions, Specify in Comments Field	PETP3101	Energy Production		Crude Oil and Natural Gas	Regional
31088803	Industrial Processes, Oil and Gas Production, Fugitive Emissions, Specify in Comments Field	PETP3101	Energy Production		Crude Oil and Natural Gas	Regional
31088804	Industrial Processes, Oil and Gas Production, Fugitive Emissions, Specify in Comments Field	PETP3101	Energy Production		Crude Oil and Natural Gas	Regional
31088805	Industrial Processes, Oil and Gas Production, Fugitive Emissions, Specify in Comments Field	PETP3101	Energy Production		Crude Oil and Natural Gas	Regional

SCC	SCC DESCRIPTION	INDICATOR CODE(S)	ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
			SECTOR(S)	SUBSECTOR(S)	FUEL TYPE	GEOGRAPHIC RESOLUTION
31088811	Industrial Processes, Oil and Gas Production, Fugitive Emissions, Fugitive Emissions	PETP3101	Energy Production		Crude Oil and Natural Gas	Regional
31390003	Industrial Processes, Electrical Equipment, Process Heaters, Natural Gas	INDC1702	Industrial	Metals-Based Durables	Natural Gas	National
39000189	Industrial Processes, In-process Fuel Use, Anthracite Coal, General	INDC2213	Industrial	Total Industrial	Total Coal	Regional
39000199	Industrial Processes, In-process Fuel Use, Anthracite Coal, General	INDC2213	Industrial	Total Industrial	Total Coal	Regional
39000201	Industrial Processes, In-process Fuel Use, Bituminous Coal, Cement Kiln/Dryer (Bituminous Coal)	INDC1404	Industrial	Cement	Steam Coal	National
39000203	Industrial Processes, In-process Fuel Use, Bituminous Coal, Lime Kiln (Bituminous)	INDC1907	Industrial	Other Manufacturing	Steam Coal	National
39000288	Industrial Processes, In-process Fuel Use, Bituminous Coal, General (Subbituminous)	INDC2213	Industrial	Total Industrial	Total Coal	Regional
39000289	Industrial Processes, In-process Fuel Use, Bituminous Coal, General (Bituminous)	INDC2213	Industrial	Total Industrial	Total Coal	Regional
39000299	Industrial Processes, In-process Fuel Use, Bituminous Coal, General (Bituminous)	INDC2213	Industrial	Total Industrial	Total Coal	Regional
39000399	Industrial Processes, In-process Fuel Use, Lignite, General	INDC2213	Industrial	Total Industrial	Total Coal	Regional
39000402	Industrial Processes, In-process Fuel Use, Residual Oil, Cement Kiln/Dryer	INDC1403	Industrial	Cement	Residual	National
39000403	Industrial Processes, In-process Fuel Use, Residual Oil, Lime Kiln	INDC1906	Industrial	Other Manufacturing	Residual	National
39000489	Industrial Processes, In-process Fuel Use, Residual Oil, General	INDC2211	Industrial	Total Industrial	Residual	Regional
39000499	Industrial Processes, In-process Fuel Use, Residual Oil, General	INDC2211	Industrial	Total Industrial	Residual	Regional
39000501	Industrial Processes, In-process Fuel Use, Distillate Oil, Asphalt Dryer **	INDC2101	Industrial	Refining	Distillate	National
39000502	Industrial Processes, In-process Fuel Use, Distillate Oil, Cement Kiln/Dryer	INDC1401	Industrial	Cement	Distillate	National
39000503	Industrial Processes, In-process Fuel Use, Distillate Oil, Lime Kiln	INDC1901	Industrial	Other Manufacturing	Distillate	National
39000589	Industrial Processes, In-process Fuel Use, Distillate Oil, General	INDC2202	Industrial	Total Industrial	Distillate	Regional
39000598	Industrial Processes, In-process Fuel Use, Distillate Oil, Grade 4 Oil: General	INDC2202	Industrial	Total Industrial	Distillate	Regional
39000599	Industrial Processes, In-process Fuel Use, Distillate Oil, General	INDC2202	Industrial	Total Industrial	Distillate	Regional
39000602	Industrial Processes, In-process Fuel Use, Natural Gas, Cement Kiln/Dryer	INDC1402	Industrial	Cement	Natural Gas	National
39000603	Industrial Processes, In-process Fuel Use, Natural Gas, Lime Kiln	INDC1903	Industrial	Other Manufacturing	Natural Gas	National
39000605	Industrial Processes, In-process Fuel Use, Natural Gas, Metal Melting **	INDC1603	Industrial	Iron and Steel	Natural Gas	National
39000689	Industrial Processes, In-process Fuel Use, Natural Gas, General	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
39000698		INDC2206	Industrial	Total Industrial	Natural Gas	Regional
39000699	Industrial Processes, In-process Fuel Use, Natural Gas, General	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
39000701	Industrial Processes, In-process Fuel Use, Process Gas, Coke Oven or Blast Furnace	INDC1602	Industrial	Iron and Steel	Metallurgical Coal	National
39000702	Industrial Processes, In-process Fuel Use, Process Gas, Coke Oven Gas	INDC1602	Industrial	Iron and Steel	Metallurgical Coal	National

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
39000788	Industrial Processes, In-process Fuel Use, Process Gas, General	INDC2201	Industrial	Total Industrial	Delivered Energy	Regional
39000789	Industrial Processes, In-process Fuel Use, Process Gas, Coke Oven Gas	INDC1602	Industrial	Iron and Steel	Metallurgical Coal	National
39000797	Industrial Processes, In-process Fuel Use, Process Gas, General	INDC2201	Industrial	Total Industrial	Delivered Energy	Regional
39000799	Industrial Processes, In-process Fuel Use, Process Gas, General	INDC2201	Industrial	Total Industrial	Delivered Energy	Regional
39000801	Industrial Processes, In-process Fuel Use, Coke, Mineral Wool Fuel **	INDC2204	Industrial	Total Industrial	Metallurgical Coal	Regional
39000889	Industrial Processes, In-process Fuel Use, Coke, General	INDC2204	Industrial	Total Industrial	Metallurgical Coal	Regional
39000899	Industrial Processes, In-process Fuel Use, Coke, General: Coke	INDC2204	Industrial	Total Industrial	Metallurgical Coal	Regional
39000989	Industrial Processes, In-process Fuel Use, Wood, General	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
39000999	Industrial Processes, In-process Fuel Use, Wood, General: Wood	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
39001089	Industrial Processes, In-process Fuel Use, Liquified Petroleum Gas, General	INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
39001099	Industrial Processes, In-process Fuel Use, Liquified Petroleum Gas, General	INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
39001299	Industrial Processes, In-process Fuel Use, Solid Waste, General	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
39001389	Industrial Processes, In-process Fuel Use, Liquid Waste, General	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
39001399	Industrial Processes, In-process Fuel Use, Liquid Waste, General	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
39005599		INDC2202	Industrial	Total Industrial	Distillate	Regional
39010099		INDC2208	Industrial	Total Industrial	Petroleum Subtotal	Regional
39990001	Industrial Processes, Miscellaneous Manufacturing Industries, Miscellaneous Manufacturing Industries, Distillate Oil (No. 2): Process Heaters	INDC1901	Industrial	Other Manufacturing	Distillate	National
39990002	Industrial Processes, Miscellaneous Manufacturing Industries, Miscellaneous Manufacturing Industries, Residual Oil: Process Heaters	INDC1906	Industrial	Other Manufacturing	Residual	National
39990003	Industrial Processes, Miscellaneous Manufacturing Industries, Miscellaneous Manufacturing Industries, Natural Gas: Process Heaters	INDC1903	Industrial	Other Manufacturing	Natural Gas	National

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
39990004	Industrial Processes, Miscellaneous Manufacturing Industries, Miscellaneous Manufacturing Industries, Process Gas: Process Heaters	INDC1908	Industrial	Other Manufacturing	Total	National
39990013	Industrial Processes, Miscellaneous Manufacturing Industries, Miscellaneous Manufacturing Industries, Natural Gas: Incinerators	INDC1903	Industrial	Other Manufacturing	Natural Gas	National
39990014	Industrial Processes, Miscellaneous Manufacturing Industries, Miscellaneous Manufacturing Industries, Process Gas: Incinerators	INDC1908	Industrial	Other Manufacturing	Total	National
39990022	Industrial Processes, Miscellaneous Manufacturing Industries, Miscellaneous Manufacturing Industries, Residual Oil: Flares	INDC1906	Industrial	Other Manufacturing	Residual	National
39990023	Industrial Processes, Miscellaneous Manufacturing Industries, Miscellaneous Manufacturing Industries, Natural Gas: Flares	INDC1903	Industrial	Other Manufacturing	Natural Gas	National
39990024	Industrial Processes, Miscellaneous Manufacturing Industries, Miscellaneous Manufacturing Industries, Process Gas: Flares	INDC1908	Industrial	Other Manufacturing	Total	National
39991013		INDC1903	Industrial	Other Manufacturing	Natural Gas	National
40201001	Petroleum and Solvent Evaporation, Surface Coating Operations, Coating Oven Heater, Natural Gas	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
40201002	Petroleum and Solvent Evaporation, Surface Coating Operations, Coating Oven Heater, Distillate Oil	INDC2202	Industrial	Total Industrial	Distillate	Regional
40201003	Petroleum and Solvent Evaporation, Surface Coating Operations, Coating Oven Heater, Residual Oil	INDC2211	Industrial	Total Industrial	Residual	Regional
40201004	Petroleum and Solvent Evaporation, Surface Coating Operations, Coating Oven Heater, Liquified Petroleum Gas (LPG)	INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
40290011	Petroleum and Solvent Evaporation, Surface Coating Operations, Fuel Fired Equipment, Distillate Oil: Incinerator/Afterburner	INDC2202	Industrial	Total Industrial	Distillate	Regional
40290013	Petroleum and Solvent Evaporation, Surface Coating Operations, Fuel Fired Equipment, Natural Gas: Incinerator/Afterburner	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
40290023	Petroleum and Solvent Evaporation, Surface Coating Operations, Fuel Fired Equipment, Natural Gas: Flares	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
40300101	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Gasoline **	PETS3001	Energy Production		Refined Petroleum Products	National
40300102	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Crude **	PETS3001	Energy Production		Refined Petroleum Products	National
40300103	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Gasoline **	PETS3001	Energy Production		Refined Petroleum Products	National

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40300104	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Crude **	PETS3001	Energy Production		Refined Petroleum Products	National
40300105	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Jet Fuel **	PETS3001	Energy Production		Refined Petroleum Products	National
40300106	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Kerosene **	PETS3001	Energy Production		Refined Petroleum Products	National
40300107	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Dist Fuel **	PETS3001	Energy Production		Refined Petroleum Products	National
40300108	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Benzene **	PETS3001	Energy Production		Refined Petroleum Products	National
40300109	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Cyclohexane **	PETS3001	Energy Production		Refined Petroleum Products	National
40300111	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Heptane **	PETS3001	Energy Production		Refined Petroleum Products	National
40300112	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Hexane **	PETS3001	Energy Production		Refined Petroleum Products	National
40300115	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Pentane **	PETS3001	Energy Production		Refined Petroleum Products	National
40300116	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Toluene **	PETS3001	Energy Production		Refined Petroleum Products	National
40300150	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Jet Fuel **	PETS3001	Energy Production		Refined Petroleum Products	National
40300151	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Kerosene **	PETS3001	Energy Production		Refined Petroleum Products	National

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40300152	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Dist Fuel **	PETS3001	Energy Production		Refined Petroleum Products	National
40300153	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Benzene **	PETS3001	Energy Production		Refined Petroleum Products	National
40300154	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Cyclohexane **	PETS3001	Energy Production		Refined Petroleum Products	National
40300156	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Heptane **	PETS3001	Energy Production		Refined Petroleum Products	National
40300157	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Hexane **	PETS3001	Energy Production		Refined Petroleum Products	National
40300159	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Isopentane **	PETS3001	Energy Production		Refined Petroleum Products	National
40300160	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Pentane **	PETS3001	Energy Production		Refined Petroleum Products	National
40300161	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), Toluene **	PETS3001	Energy Production		Refined Petroleum Products	National
40300197		PETS3001	Energy Production		Refined Petroleum Products	National
40300198	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), See Comment **	PETS3001	Energy Production		Refined Petroleum Products	National
40300199	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-010 and 4-07), See Comment **	PETS3001	Energy Production		Refined Petroleum Products	National
40300201	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Gasoline **	PETS3001	Energy Production		Refined Petroleum Products	National

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40300202	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Product **	PETS3001	Energy Production		Refined Petroleum Products	National
40300203	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Crude **	PETS3001	Energy Production		Refined Petroleum Products	National
40300204	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Crude **	PETS3001	Energy Production		Refined Petroleum Products	National
40300205	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Jet Fuel **	PETS3001	Energy Production		Refined Petroleum Products	National
40300207	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Dist Fuel **	PETS3001	Energy Production		Refined Petroleum Products	National
40300208	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Benzene **	PETS3001	Energy Production		Refined Petroleum Products	National
40300209	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Cyclohexane **	PETS3001	Energy Production		Refined Petroleum Products	National
40300210	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Cyclopentane **	PETS3001	Energy Production		Refined Petroleum Products	National
40300212	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Hexane **	PETS3001	Energy Production		Refined Petroleum Products	National
40300216	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Toluene **	PETS3001	Energy Production		Refined Petroleum Products	National
40300299	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Specify Liquid **	PETS3001	Energy Production		Refined Petroleum Products	National
40300302	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Deleted - Do Not Use (See 4-03-011 and 4-07), Gasoline **	PETS3001	Energy Production		Refined Petroleum Products	National

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40301001	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Gasoline RVP 13: Breathing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301002	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Gasoline RVP 10: Breathing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301003	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Gasoline RVP 7: Breathing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301004	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Gasoline RVP 13: Breathing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301005	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Gasoline RVP 10: Breathing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301006	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Gasoline RVP 7: Breathing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301007	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Gasoline RVP 13: Working Loss (Tank Diameter Independent)	PETS3001	Energy Production		Refined Petroleum Products	National
40301008	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Gasoline RVP 10: Working Loss (Tank Diameter Independent)	PETS3001	Energy Production		Refined Petroleum Products	National
40301009	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Gasoline RVP 7: Working Loss (Tank Diameter Independent)	PETS3001	Energy Production		Refined Petroleum Products	National
40301010	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Crude Oil RVP 5: Breathing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301011	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Crude Oil RVP 5: Breathing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301012	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Crude Oil RVP 5: Working Loss (Tank Diameter Independent)	PETS3001	Energy Production		Refined Petroleum Products	National

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40301013	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Jet Naphtha (JP-4): Breathing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301014	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Jet Naphtha (JP-4): Breathing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301015	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Jet Naphtha (JP-4): Working Loss (Tank Diameter Independent)	PETS3001	Energy Production		Refined Petroleum Products	National
40301016	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Jet Kerosene: Breathing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301017	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Jet Kerosene: Breathing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301018	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Jet Kerosene: Working Loss (Tank Diameter Independent)	PETS3001	Energy Production		Refined Petroleum Products	National
40301019	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Distillate Fuel #2: Breathing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301020	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Distillate Fuel #2: Breathing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301021	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Distillate Fuel #2: Working Loss (Tank Diameter Independent)	PETS3001	Energy Production		Refined Petroleum Products	National
40301068	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Grade 2 Fuel Oil: Breathing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301078	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Grade 2 Fuel Oil: Working Loss (Independent Tank Diameter)	PETS3001	Energy Production		Refined Petroleum Products	National
40301097	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Specify Liquid: Breathing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	SCC DESCRIPTION	INDICATOR CODE(S)	SECTOR(S)	SUBSECTOR(S)	FUEL TYPE	GEOGRAPHIC RESOLUTION
40301098	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Specify Liquid: Breathing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301099	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fixed Roof Tanks (Varying Sizes), Specify Liquid: Working Loss (Tank Diameter Independent)	PETS3001	Energy Production		Refined Petroleum Products	National
40301101	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Gasoline RVP 13: Standing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301102	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Gasoline RVP 10: Standing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301103	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Gasoline RVP 7: Standing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301104	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Gasoline RVP 13: Standing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301105	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Gasoline RVP 10: Standing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301106	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Gasoline RVP 7: Standing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301107	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Gasoline RVP 13/10/7: Withdrawal Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301108	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Gasoline RVP 13/10/7: Withdrawal Loss (250000 Bbl.Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301109	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Crude Oil RVP 5: Standing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301110	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Crude Oil RVP 5: Standing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40301111	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Jet Naphtha (JP-4): Standing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301112	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Jet Naphtha (JP-4): Standing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301113	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Jet Kerosene: Standing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301114	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Jet Kerosene: Standing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301115	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Distillate Fuel #2: Standing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301116	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Distillate Fuel #2: Standing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301117	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Crude Oil RVP 5: Withdrawal Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40301118	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Jet Naphtha (JP-4): Withdrawal Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40301119	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Jet Kerosene: Withdrawal Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40301120	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Distillate Fuel #2: Withdrawal Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40301130	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Specify Liquid: Standing Loss - External - Primary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40301131	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Gasoline: Standing Loss - External - Primary Seal	PETS3001	Energy Production		Refined Petroleum Products	National

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40301132	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Crude Oil: Standing Loss - External - Primary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40301133	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Jet Naphtha (JP-4): Standing Loss - External - Primary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40301134	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Jet Kerosene: Standing Loss - External - Primary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40301135	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Distillate Fuel #2: Standing Loss - External - Primary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40301140	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Specify Liquid: Standing Loss - External - Secondary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40301141	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Gasoline: Standing Loss - External - Secondary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40301142	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Crude Oil: Standing Loss - External - Secondary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40301143	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Jet Naphtha (JP-4): Standing Loss - External - Secondary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40301144	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Jet Kerosene: Standing Loss - External - Secondary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40301145	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Distillate Fuel #2: Standing Loss - External - Secondary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40301150	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Specify Liquid: Standing Loss - Internal	PETS3001	Energy Production		Refined Petroleum Products	National
40301151	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Gasoline: Standing Loss - Internal	PETS3001	Energy Production		Refined Petroleum Products	National

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40301152	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Crude Oil: Standing Loss - Internal	PETS3001	Energy Production		Refined Petroleum Products	National
40301153	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Jet Naphtha (JP-4): Standing Loss - Internal	PETS3001	Energy Production		Refined Petroleum Products	National
40301154	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Jet Kerosene: Standing Loss - Internal	PETS3001	Energy Production		Refined Petroleum Products	National
40301155	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Distillate Fuel #2: Standing Loss - Internal	PETS3001	Energy Production		Refined Petroleum Products	National
40301197	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Specify Liquid: Withdrawal Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40301198	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Specify Liquid: Standing Loss (67000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301199	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Floating Roof Tanks (Varying Sizes), Specify Liquid: Standing Loss (250000 Bbl. Tank Size)	PETS3001	Energy Production		Refined Petroleum Products	National
40301201	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Variable Vapor Space, Gasoline RVP 13: Filling Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40301202	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Variable Vapor Space, Gasoline RVP 10: Filling Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40301203	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Variable Vapor Space, Gasoline RVP 7: Filling Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40301204	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Variable Vapor Space, Jet Naphtha (JP-4): Filling Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40301205	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Variable Vapor Space, Jet Kerosene: Filling Loss	PETS3001	Energy Production		Refined Petroleum Products	National

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SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40301206	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Variable Vapor Space, Distillate Fuel #2: Filling Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40301299	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Variable Vapor Space, Specify Liquid: Filling Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40388801	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
40388802	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
40388803	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
40388804	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
40388805	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
40399999	Petroleum and Solvent Evaporation, Petroleum Product Storage at Refineries, Other Not Classified, See Comment **	PETS3001	Energy Production		Refined Petroleum Products	National
40400101	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13: Breathing Loss (67000 Bbl Capacity) - Fixed Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400102	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 10: Breathing Loss (67000 Bbl Capacity) - Fixed Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400103	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 7: Breathing Loss (67000 Bbl. Capacity) - Fixed Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400104	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13: Breathing Loss (250000 Bbl Capacity)-Fixed Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National

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SCC	SCC DESCRIPTION	INDICATOR CODE(S)	SECTOR(S)	SUBSECTOR(S)	FUEL TYPE	GEOGRAPHIC RESOLUTION
40400105	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 10: Breathing Loss (250000 Bbl Capacity)-Fixed Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400106	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 7: Breathing Loss (250000 Bbl Capacity) - Fixed Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400107	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13: Working Loss (Diam. Independent) - Fixed Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400108	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 10: Working Loss (Diameter Independent) - Fixed Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400109	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 7: Working Loss (Diameter Independent) - Fixed Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400110	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13: Standing Loss (67000 Bbl Capacity)-Floating Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400111	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 10: Standing Loss (67000 Bbl Capacity)-Floating Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400112	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 7: Standing Loss (67000 Bbl Capacity)- Floating Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400113	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13: Standing Loss (250000 Bbl Cap.) - Floating Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400114	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 10: Standing Loss (250000 Bbl Cap.) - Floating Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400115	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 7: Standing Loss (250000 Bbl Cap.) - Floating Roof Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40400116	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13/10/7: Withdrawal Loss (67000 Bbl Cap.) - Float RfTnk	PETS3001	Energy Production		Refined Petroleum Products	National

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40400117	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13/10/7: Withdrawal Loss (250000 Bbl Cap.) - Float RfTnk	PETS3001	Energy Production		Refined Petroleum Products	National
40400118	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13: Filling Loss (10500 Bbl Cap.) - Variable Vapor Space	PETS3001	Energy Production		Refined Petroleum Products	National
40400119	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 10: Filling Loss (10500 Bbl Cap.) - Variable Vapor Space	PETS3001	Energy Production		Refined Petroleum Products	National
40400120	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 7: Filling Loss (10500 Bbl Cap.) - Variable Vapor Space	PETS3001	Energy Production		Refined Petroleum Products	National
40400130	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Specify Liquid: Standing Loss - External Floating Roof w/ Primary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40400131	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13: Standing Loss - Ext. Floating Roof w/ Primary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40400140	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Specify Liquid: Standing Loss - Ext. Float Roof Tank w/ Second'y Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40400141	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13: Standing Loss - Ext. Floating Roof w/ Secondary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40400150	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Miscellaneous Losses/Leaks: Loading Racks	PETS3001	Energy Production		Refined Petroleum Products	National
40400151	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Valves, Flanges, and Pumps	PETS3001	Energy Production		Refined Petroleum Products	National
40400152	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Vapor Collection Losses	PETS3001	Energy Production		Refined Petroleum Products	National
40400153	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Vapor Control Unit Losses	PETS3001	Energy Production		Refined Petroleum Products	National

SCC	SCC DESCRIPTION	INDICATOR CODE(S)	ANNUAL ENERGY OUTLOOK 2005 VARIABLE SECTOR(S)	SUBSECTOR(S)	FUEL TYPE	GEOGRAPHIC RESOLUTION
40400154	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Tank Truck Vapor Leaks	PETS3001	Energy Production		Refined Petroleum Products	National
40400160	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Specify Liquid: Standing Loss - Internal Floating Roof w/ Primary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40400161	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13: Standing Loss - Int. Floating Roof w/ Primary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40400170	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Specify Liquid: Standing Loss - Int. Floating Roof w/ Secondary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40400171	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13: Standing Loss - Int. Floating Roof w/ Secondary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40400178	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, Gasoline RVP 13/10/7: Withdrawal Loss - Int. Float Roof (Pri/Sec Seal)	PETS3001	Energy Production		Refined Petroleum Products	National
40400199	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Terminals, See Comment **	PETS3001	Energy Production		Refined Petroleum Products	National
40400201	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 13: Breathing Loss (67000 Bbl Capacity) - Fixed Roof Tank	TRAN4001	Transportation		Motor Gasoline	Regional
40400202	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 10: Breathing Loss (67000 Bbl Capacity) - Fixed Roof Tank	TRAN4001	Transportation		Motor Gasoline	Regional
40400203	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 7: Breathing Loss (67000 Bbl. Capacity) - Fixed Roof Tank	TRAN4001	Transportation		Motor Gasoline	Regional
40400204	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 13: Working Loss (67000 Bbl. Capacity) - Fixed Roof Tank	TRAN4001	Transportation		Motor Gasoline	Regional
40400205	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 10: Working Loss (67000 Bbl. Capacity) - Fixed Roof Tank	TRAN4001	Transportation		Motor Gasoline	Regional
40400206	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 7: Working Loss (67000 Bbl. Capacity) - Fixed Roof Tank	TRAN4001	Transportation		Motor Gasoline	Regional
40400207	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 13: Standing Loss (67000 Bbl Cap.) - Floating Roof Tank	TRAN4001	Transportation		Motor Gasoline	Regional
40400208	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 10: Standing Loss (67000 Bbl Cap.) - Floating Roof Tank	TRAN4001	Transportation		Motor Gasoline	Regional

SCC	SCC DESCRIPTION	INDICATOR CODE(S)	ANNUAL ENERGY OUTLOOK 2005 VARIABLE SECTOR(S)	SUBSECTOR(S)	FUEL TYPE	GEOGRAPHIC RESOLUTION
40400209	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 7: Standing Loss (67000 Bbl Cap.) - Floating Roof Tank	TRAN4001	Transportation		Motor Gasoline	Regional
40400210	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 13/10/7: Withdrawal Loss (67000 Bbl Cap.) - Float RfTnk	TRAN4001	Transportation		Motor Gasoline	Regional
40400211	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 13: Filling Loss (10500 Bbl Cap.) - Variable Vapor Space	TRAN4001	Transportation		Motor Gasoline	Regional
40400212	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 10: Filling Loss (10500 Bbl Cap.) - Variable Vapor Space	TRAN4001	Transportation		Motor Gasoline	Regional
40400230	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Specify Liquid: Standing Loss - External Floating Roof w/ Primary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40400231	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 13: Standing Loss - Ext. Floating Roof w/ Primary Seal	TRAN4001	Transportation		Motor Gasoline	Regional
40400240	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Specify Liquid: Standing Loss - Ext. Floating Roof w/ Secondary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40400241	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 13: Standing Loss - Ext. Floating Roof w/ Secondary Seal	TRAN4001	Transportation		Motor Gasoline	Regional
40400250	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Loading Racks	PETS3001	Energy Production		Refined Petroleum Products	National
40400251	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Valves, Flanges, and Pumps	PETS3001	Energy Production		Refined Petroleum Products	National
40400254	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Tank Truck Vapor Losses	PETS3001	Energy Production		Refined Petroleum Products	National
40400260	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Specify Liquid: Standing Loss - Internal Floating Roof w/ Primary Seal	PETS3001	Energy Production		Refined Petroleum Products	National
40400261	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 13: Standing Loss - Int. Floating Roof w/ Primary Seal	TRAN4001	Transportation		Motor Gasoline	Regional
40400271	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Bulk Plants, Gasoline RVP 13: Standing Loss - Int. Floating Roof w/ Secondary Seal	TRAN4001	Transportation		Motor Gasoline	Regional
40400298		PETS3001	Energy Production		Refined Petroleum Products	National

SCC	SCC DESCRIPTION	INDICATOR CODE(S)	ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
			SECTOR(S)	SUBSECTOR(S)	FUEL TYPE	GEOGRAPHIC RESOLUTION
40400401	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Petroleum Products - Underground Tanks, Gasoline RVP 13: Breathing Loss	TRAN4001	Transportation		Motor Gasoline	Regional
40400402	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Petroleum Products - Underground Tanks, Gasoline RVP 13: Working Loss	TRAN4001	Transportation		Motor Gasoline	Regional
40400403	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Petroleum Products - Underground Tanks, Gasoline RVP 10: Breathing Loss	TRAN4001	Transportation		Motor Gasoline	Regional
40400404	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Petroleum Products - Underground Tanks, Gasoline RVP 10: Working Loss	TRAN4001	Transportation		Motor Gasoline	Regional
40400405	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Petroleum Products - Underground Tanks, Gasoline RVP 7: Breathing Loss	TRAN4001	Transportation		Motor Gasoline	Regional
40400406	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Petroleum Products - Underground Tanks, Gasoline RVP 7: Working Loss	TRAN4001	Transportation		Motor Gasoline	Regional
40400407	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Petroleum Products - Underground Tanks, Crude Oil RVP 5: Breathing Loss	PETP3106	Energy Production		Crude Oil	Regional
40400408	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Petroleum Products - Underground Tanks, Crude Oil RVP 5: Working Loss	PETP3106	Energy Production		Crude Oil	Regional
40400413	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Petroleum Products - Underground Tanks, Distillate Fuel #2: Breathing Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40400414	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Petroleum Products - Underground Tanks, Distillate Fuel #2: Working Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40400497	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Petroleum Products - Underground Tanks, Specify Liquid: Breathing Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40400498	Petroleum and Solvent Evaporation, Petroleum Liquids Storage (non-Refinery), Petroleum Products - Underground Tanks, Specify Liquid: Working Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40400815		PETS3001	Energy Production		Refined Petroleum Products	National
40600101	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Gasoline: Splash Loading **	TRAN4001	Transportation		Motor Gasoline	Regional
40600126	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Gasoline: Submerged Loading **	TRAN4001	Transportation		Motor Gasoline	Regional
40600131	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Gasoline: Submerged Loading (Normal Service)	TRAN4001	Transportation		Motor Gasoline	Regional

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40600132	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Crude Oil: Submerged Loading (Normal Service)	PETS3001	Energy Production		Refined Petroleum Products	National
40600136	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Gasoline: Splash Loading (Normal Service)	TRAN4001	Transportation		Motor Gasoline	Regional
40600137	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Crude Oil: Splash Loading (Normal Service)	PETS3001	Energy Production		Refined Petroleum Products	National
40600141	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Gasoline: Submerged Loading (Balanced Service)	TRAN4001	Transportation		Motor Gasoline	Regional
40600142	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Crude Oil: Submerged Loading (Balanced Service)	PETS3001	Energy Production		Refined Petroleum Products	National
40600144	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Gasoline: Splash Loading (Balanced Service)	TRAN4001	Transportation		Motor Gasoline	Regional
40600145	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Crude Oil: Splash Loading (Balanced Service)	PETS3001	Energy Production		Refined Petroleum Products	National
40600147	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Gasoline: Submerged Loading (Clean Tanks)	TRAN4001	Transportation		Motor Gasoline	Regional
40600148	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Crude Oil: Submerged Loading (Clean Tanks)	PETS3001	Energy Production		Refined Petroleum Products	National
40600162	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Gasoline: Loaded with Fuel (Transit Losses)	TRAN4001	Transportation		Motor Gasoline	Regional
40600163	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Gasoline: Return with Vapor (Transit Losses)	TRAN4001	Transportation		Motor Gasoline	Regional
40600197	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Not Classified **	PETS3001	Energy Production		Refined Petroleum Products	National
40600198	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Not Classified **	PETS3001	Energy Production		Refined Petroleum Products	National
40600199	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Tank Cars and Trucks, Not Classified **	PETS3001	Energy Production		Refined Petroleum Products	National

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40600231	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Gasoline: Ship Loading - Cleaned and Vapor Free Tanks	PETS3001	Energy Production		Refined Petroleum Products	National
40600232	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Gasoline: Ocean Barges Loading	PETS3001	Energy Production		Refined Petroleum Products	National
40600233	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Gasoline: Barge Loading - Cleaned and Vapor Free Tanks	PETS3001	Energy Production		Refined Petroleum Products	National
40600234	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Gasoline: Ship Loading - Ballasted Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40600235	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Gasoline: Ocean Barges Loading - Ballasted Tank	PETS3001	Energy Production		Refined Petroleum Products	National
40600236	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Gasoline: Ship Loading - Uncleaned Tanks	PETS3001	Energy Production		Refined Petroleum Products	National
40600237	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Gasoline: Ocean Barges Loading - Uncleaned Tanks	PETS3001	Energy Production		Refined Petroleum Products	National
40600238	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Gasoline: Barges Loading - Uncleaned Tanks	PETS3001	Energy Production		Refined Petroleum Products	National
40600239	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Gasoline: Tanker Ship - Ballasted Tank Condition	PETS3001	Energy Production		Refined Petroleum Products	National
40600240	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Gasoline: Barge Loading - Average Tank Condition	PETS3001	Energy Production		Refined Petroleum Products	National
40600242	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Gasoline: Transit Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40600243	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Crude Oil: Loading Tankers	PETS3001	Energy Production		Refined Petroleum Products	National

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40600244	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Jet Fuel: Loading Tankers	PETS3001	Energy Production		Refined Petroleum Products	National
40600245	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Kerosene: Loading Tankers	PETS3001	Energy Production		Refined Petroleum Products	National
40600246	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Distillate Oil: Loading Tankers	PETS3001	Energy Production		Refined Petroleum Products	National
40600248	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Crude Oil: Loading Barges	PETS3001	Energy Production		Refined Petroleum Products	National
40600249	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Jet Fuel: Loading Barges	PETS3001	Energy Production		Refined Petroleum Products	National
40600250	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Kerosene: Loading Barges	PETS3001	Energy Production		Refined Petroleum Products	National
40600251	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Distillate Oil: Loading Barges	PETS3001	Energy Production		Refined Petroleum Products	National
40600253	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Crude Oil: Tanker Ballasting	PETS3001	Energy Production		Refined Petroleum Products	National
40600254	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Crude Oil: Transit Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40600257	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Distillate Oil: Transit Loss	PETS3001	Energy Production		Refined Petroleum Products	National
40600259	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Tanker/Barge Cleaning	PETS3001	Energy Production		Refined Petroleum Products	National
40600298	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Not Classified **	PETS3001	Energy Production		Refined Petroleum Products	National

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
40600299	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Marine Vessels, Not Classified **	PETS3001	Energy Production		Refined Petroleum Products	National
40600301	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Gasoline Retail Operations - Stage I, Splash Filling	TRAN4001	Transportation		Motor Gasoline	Regional
40600302	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Gasoline Retail Operations - Stage I, Submerged Filling w/o Controls	TRAN4001	Transportation		Motor Gasoline	Regional
40600306	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Gasoline Retail Operations - Stage I, Balanced Submerged Filling	TRAN4001	Transportation		Motor Gasoline	Regional
40600307	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Gasoline Retail Operations - Stage I, Underground Tank Breathing and Emptying	TRAN4001	Transportation		Motor Gasoline	Regional
40600399	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Gasoline Retail Operations - Stage I, Not Classified **	TRAN4001	Transportation		Motor Gasoline	Regional
40600401	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Filling Vehicle Gas Tanks - Stage II, Vapor Loss w/o Controls	TRAN4001	Transportation		Motor Gasoline	Regional
40600402	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Filling Vehicle Gas Tanks - Stage II, Liquid Spill Loss w/o Controls	TRAN4001	Transportation		Motor Gasoline	Regional
40600403	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Filling Vehicle Gas Tanks - Stage II, Vapor Loss w/o Controls	TRAN4001	Transportation		Motor Gasoline	Regional
40600499	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Filling Vehicle Gas Tanks - Stage II, Not Classified **	TRAN4001	Transportation		Motor Gasoline	Regional
40688801	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
40688802	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
40688803	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
40688804	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National
40688805	Petroleum and Solvent Evaporation, Transportation and Marketing of Petroleum Products, Fugitive Emissions, Specify in Comments Field	PETS3001	Energy Production		Refined Petroleum Products	National

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
49090011	Petroleum and Solvent Evaporation, Organic Solvent Evaporation, Fuel Fired Equipment, Distillate Oil (No. 2): Incinerators	INDC2202	Industrial	Total Industrial	Distillate	Regional
49090013	Petroleum and Solvent Evaporation, Organic Solvent Evaporation, Fuel Fired Equipment, Natural Gas: Incinerators	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
49090023	Petroleum and Solvent Evaporation, Organic Solvent Evaporation, Fuel Fired Equipment, Natural Gas: Flares	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
50100103	Waste Disposal, Solid Waste Disposal - Government, Municipal Incineration, Refuse Derived Fuel	COMC1109	Commercial		Renewable Energy	Regional
50190005	Waste Disposal, Solid Waste Disposal - Government, Auxillary Fuel/No Emissions, Distillate Oil	COMC1103	Commercial		Distillate	Regional
50190006	Waste Disposal, Solid Waste Disposal - Government, Auxillary Fuel/No Emissions, Natural Gas	COMC1107	Commercial		Natural Gas	Regional
50190010	Waste Disposal, Solid Waste Disposal - Government, Auxillary Fuel/No Emissions, Liquified Petroleum Gas (LPG)	COMC1105	Commercial		Liquified Petroleum Gas	Regional
50200601	Waste Disposal, Solid Waste Disposal - Commercial/Institutional, Landfill Dump, Waste Gas Flares ** (Use 5-01-004-10)	COMC1109	Commercial		Renewable Energy	Regional
50290005	Waste Disposal, Solid Waste Disposal - Commercial/Institutional, Auxillary Fuel/No Emissions, Distillate Oil	COMC1103	Commercial		Distillate	Regional
50290006	Waste Disposal, Solid Waste Disposal - Commercial/Institutional, Auxillary Fuel/No Emissions, Natural Gas	COMC1107	Commercial		Natural Gas	Regional
50290010	Waste Disposal, Solid Waste Disposal - Commercial/Institutional, Auxillary Fuel/No Emissions, Liquified Petroleum Gas (LPG)	COMC1105	Commercial		Liquified Petroleum Gas	Regional
50290099		COMC1102	Commercial		Delivered Energy	Regional
50300601	Waste Disposal, Solid Waste Disposal - Industrial, Landfill Dump, Waste Gas Flares	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
50390005	Waste Disposal, Solid Waste Disposal - Industrial, Auxillary Fuel/No Emissions, Distillate Oil	INDC2202	Industrial	Total Industrial	Distillate	Regional
50390006	Waste Disposal, Solid Waste Disposal - Industrial, Auxillary Fuel/No Emissions, Natural Gas	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
50390007	Waste Disposal, Solid Waste Disposal - Industrial, Auxillary Fuel/No Emissions, Process Gas	INDC2201	Industrial	Total Industrial	Delivered Energy	Regional
50390010	Waste Disposal, Solid Waste Disposal - Industrial, Auxillary Fuel/No Emissions, Liquified Petroleum Gas (LPG)	INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
2102001000	Stationary Source Fuel Combustion, Industrial, Anthracite Coal, Total: All Boiler Types	INDC2212	Industrial	Total Industrial	Steam Coal	Regional

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
2102002000	Stationary Source Fuel Combustion, Industrial, Bituminous/Subbituminous Coal, Total: All Boiler Types	INDC2212	Industrial	Total Industrial	Steam Coal	Regional
2102004000	Stationary Source Fuel Combustion, Industrial, Distillate Oil, Total: Boilers and IC Engines	INDC2202	Industrial	Total Industrial	Distillate	Regional
2102005000	Stationary Source Fuel Combustion, Industrial, Residual Oil, Total: All Boiler Types	INDC2211	Industrial	Total Industrial	Residual	Regional
2102006000	Stationary Source Fuel Combustion, Industrial, Natural Gas, Total: Boilers and IC Engines	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
2102006001	Stationary Source Fuel Combustion, Industrial, Natural Gas, All Boiler Types	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
2102006002	Stationary Source Fuel Combustion, Industrial, Natural Gas, All IC Engine Types	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
2102007000	Stationary Source Fuel Combustion, Industrial, Liquified Petroleum Gas (LPG), Total: All Boiler Types	INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
2102008000	Stationary Source Fuel Combustion, Industrial, Wood, Total: All Boiler Types	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
2102009000	Stationary Source Fuel Combustion, Industrial, Coke, Total: All Boiler Types	INDC2207	Industrial	Total Industrial	Other Petroleum	Regional
2102010000	Stationary Source Fuel Combustion, Industrial, Process Gas, Total: All Boiler Types	INDC2201	Industrial	Total Industrial	Delivered Energy	Regional
2102011000	Stationary Source Fuel Combustion, Industrial, Kerosene, Total: All Boiler Types	INDC2207	Industrial	Total Industrial	Other Petroleum	Regional
2103001000	Stationary Source Fuel Combustion, Commercial/Institutional, Anthracite Coal, Total: All Boiler Types	COMC1101	Commercial		Coal	Regional
2103002000	Stationary Source Fuel Combustion, Commercial/Institutional, Bituminous/Subbituminous Coal, Total: All Boiler Types	COMC1101	Commercial		Coal	Regional
2103004000	Stationary Source Fuel Combustion, Commercial/Institutional, Distillate Oil, Total: Boilers and IC Engines	COMC1103	Commercial		Distillate	Regional
2103005000	Stationary Source Fuel Combustion, Commercial/Institutional, Residual Oil, Total: All Boiler Types	COMC1110	Commercial		Residual	Regional
2103006000	Stationary Source Fuel Combustion, Commercial/Institutional, Natural Gas, Total: Boilers and IC Engines	COMC1107	Commercial		Natural Gas	Regional
2103007000	Stationary Source Fuel Combustion, Commercial/Institutional, Liquified Petroleum Gas (LPG), Total: All Combustor Types	COMC1105	Commercial		Liquified Petroleum Gas	Regional
2103008000	Stationary Source Fuel Combustion, Commercial/Institutional, Wood, Total: All Boiler Types	COMC1109	Commercial		Renewable Energy	Regional
2103011000	Stationary Source Fuel Combustion, Commercial/Institutional, Kerosene, Total: All Combustor Types	COMC1104	Commercial		Kerosene	Regional

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
2104001000	Stationary Source Fuel Combustion, Residential, Anthracite Coal, Total: All Combustor Types	RESC2401	Residential		Coal	Regional
2104002000	Stationary Source Fuel Combustion, Residential, Bituminous/Subbituminous Coal, Total: All Combustor Types	RESC2401	Residential		Coal	Regional
2104004000	Stationary Source Fuel Combustion, Residential, Distillate Oil, Total: All Combustor Types	RESC2403	Residential		Distillate	Regional
2104005000	Stationary Source Fuel Combustion, Residential, Residual Oil, Total: All Combustor Types	RESC2407	Residential		Petroleum Subtotal	Regional
2104006000	Stationary Source Fuel Combustion, Residential, Natural Gas, Total: All Combustor Types	RESC2406	Residential		Natural Gas	Regional
2104006010	Stationary Source Fuel Combustion : Residential : Natural Gas : Residential Furnaces	RESC2406	Residential		Natural Gas	Regional
2104007000	Stationary Source Fuel Combustion, Residential, Liquified Petroleum Gas (LPG), Total: All Combustor Types	RESC2405	Residential		Liquified Petroleum Gas	Regional
2104009000	Stationary Source Fuel Combustion : Residential : Firelog : Total: All Combustor Types	RESC2408	Residential		Renewable Energy	Regional
2104011000	Stationary Source Fuel Combustion, Residential, Kerosene, Total: All Heater Types	RESC2404	Residential		Kerosene	Regional
2199004000	Stationary Source Fuel Combustion, Total Area Source Fuel Combustion, Distillate Oil, Total: Boilers and IC Engines	TTRC2601	Total Energy - Transportation		Distillate Fuel	Regional
2199005000	Stationary Source Fuel Combustion, Total Area Source Fuel Combustion, Residual Oil, Total: All Boiler Types	TOTC2507	Total Energy		Residual Fuel	Regional
2199006000	Stationary Source Fuel Combustion, Total Area Source Fuel Combustion, Natural Gas, Total: Boilers and IC Engines	TOTC2504	Total Energy		Natural Gas	Regional
2199007000	Stationary Source Fuel Combustion, Total Area Source Fuel Combustion, Liquified Petroleum Gas (LPG), Total: All Boiler Types	TOTC2502	Total Energy		Liquified Petroleum Gas	Regional
2199011000	Stationary Source Fuel Combustion, Total Area Source Fuel Combustion, Kerosene, Total: All Heater Types	TOTC2501	Total Energy		Kerosene	Regional
2275900000	Mobile Sources, Aircraft, Refueling: All Fuels, All Processes	TRAN4002	Transportation		Jet Fuel	Regional
2275900101	Mobile Sources, Aircraft, Refueling: All Fuels, Displacement Loss/Uncontrolled	TRAN4002	Transportation		Jet Fuel	Regional
2275900102	Mobile Sources, Aircraft, Refueling: All Fuels, Displacement Loss/Controlled	TRAN4002	Transportation		Jet Fuel	Regional
2280000000	Mobile Sources, Marine Vessels, Commercial, All Fuels, Total, All Vessel Types	TRAN4006	Domestic Shipping		Total	National
2280001000	Mobile Sources, Marine Vessels, Commercial, Coal, Total, All Vessel Types	TRAN4006	Domestic Shipping		Total	National
2280002100	Mobile Sources , Marine Vessels, Commercial , Diesel , Port emissions	TRAN4004	Domestic Shipping		Distillate Fuel	National

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
2280002200	Mobile Sources , Marine Vessels, Commercial , Diesel , Underway emissions	TRAN4004	Domestic Shipping		Distillate Fuel	National
2280003000	Mobile Sources, Marine Vessels, Commercial, Residual, Total, All Vessel Types	TRAN4005	Domestic Shipping		Residual	National
2280003010	Mobile Sources, Marine Vessels, Commercial, Residual, Ocean-going Vessels	TRAN4005	Domestic Shipping		Residual	National
2280003020	Mobile Sources, Marine Vessels, Commercial, Residual, Harbor Vessels	TRAN4005	Domestic Shipping		Residual	National
2280003030	Mobile Sources, Marine Vessels, Commercial, Residual, Fishing Vessels	TRAN4005	Domestic Shipping		Residual	National
2280004020	Mobile Sources, Marine Vessels, Commercial, Gasoline, Harbor Vessels	TRAN4006	Domestic Shipping		Total	National
2285002006	Mobile Sources , Railroad Equipment , Diesel , Line Haul Locomotives: Class I Operations	TRAN4003	Freight Rail		Distillate Fuel	National
2285002007	Mobile Sources , Railroad Equipment , Diesel , Line Haul Locomotives: Class II / III Operations	TRAN4003	Freight Rail		Distillate Fuel	National
2285002010	Mobile Sources, Railroad Equipment, Diesel, Yard Locomotives	TRAN4003	Freight Rail		Distillate Fuel	National
2310000000	Industrial Processes, Oil and Gas Production: SIC 13, All Processes, Total: All Processes	PETP3101	Energy Production		Crude Oil and Natural Gas	Regional
2310010000	Industrial Processes, Oil and Gas Production: SIC 13, Crude Petroleum, Total: All Processes	PETP3106	Energy Production		Crude Oil	Regional
2310020000	Industrial Processes, Oil and Gas Production: SIC 13, Natural Gas, Total: All Processes	PETP3104	Energy Production		Natural Gas	Regional
2310030000	Industrial Processes, Oil and Gas Production: SIC 13, Natural Gas Liquids, Total: All Processes	PETP3105	Energy Production		Natural Gas Liquids	Regional
2390004000	Industrial Processes, In-process Fuel Use, Distillate Oil, Total	INDC2202	Industrial	Total Industrial	Distillate	Regional
2390005000	Industrial Processes, In-process Fuel Use, Residual Oil, Total	INDC2211	Industrial	Total Industrial	Residual	Regional
2390006000	Industrial Processes, In-process Fuel Use, Natural Gas, Total	INDC2206	Industrial	Total Industrial	Natural Gas	Regional
2390007000	Industrial Processes, In-process Fuel Use, Liquified Petroleum Gas (LPG), Total	INDC2203	Industrial	Total Industrial	Liquified Petroleum Gas	Regional
2390008000	Industrial Processes : In-process Fuel Use : Wood : Total	INDC2210	Industrial	Total Industrial	Renewable Energy	Regional
2390010000	Industrial Processes, In-process Fuel Use, Process Gas, Total	INDC2201	Industrial	Total Industrial	Delivered Energy	Regional

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
2501000000	Storage and Transport, Petroleum and Petroleum Product Storage, All Storage Types: Breathing Loss, Total: All Products	PETS3001	Energy Production		Refined Petroleum Products	National
2501000030	Storage and Transport, Petroleum and Petroleum Product Storage, All Storage Types: Breathing Loss, Crude Oil	PETS3001	Energy Production		Refined Petroleum Products	National
2501000180	Storage and Transport : Petroleum and Petroleum Product Storage : All Storage Types: Breathing Loss : Kerosene	TOTC2501	Total Energy		Kerosene	Regional
2501010000	Storage and Transport, Petroleum and Petroleum Product Storage, Commercial/Industrial: Breathing Loss, Total: All Products	PETS3001	Energy Production		Refined Petroleum Products	National
2501010030	Storage and Transport : Petroleum and Petroleum Product Storage : Commercial/Industrial: Breathing Loss : Crude Oil	PETS3001	Energy Production		Refined Petroleum Products	National
2501010060	Storage and Transport : Petroleum and Petroleum Product Storage : Commercial/Industrial: Breathing Loss : Residual Oil	COMC1110	Commercial		Residual	Regional
2501010180	Storage and Transport : Petroleum and Petroleum Product Storage : Commercial/Industrial: Breathing Loss : Kerosene	COMC1104	Commercial		Kerosene	Regional
2501050000	Storage and Transport, Petroleum and Petroleum Product Storage, Bulk Stations/Terminals: Breathing Loss, Total: All Products	PETS3001	Energy Production		Refined Petroleum Products	National
2501050030	Storage and Transport, Petroleum and Petroleum Product Storage, Bulk Stations/Terminals: Breathing Loss, Crude Oil	PETS3001	Energy Production		Refined Petroleum Products	National
2501050060	Storage and Transport, Petroleum and Petroleum Product Storage, Bulk Stations/Terminals: Breathing Loss, Residual Oil	TOTC2507	Total Energy		Residual Fuel	Regional
2501050090	Storage and Transport, Petroleum and Petroleum Product Storage, Bulk Stations/Terminals: Breathing Loss, Distillate Oil	TOTC2505	Total Energy		Other Petroleum	Regional
2501050120	Storage and Transport, Petroleum and Petroleum Product Storage, Bulk Stations/Terminals: Breathing Loss, Gasoline	TRAN4001	Transportation		Motor Gasoline	Regional
2501050150	Storage and Transport, Petroleum and Petroleum Product Storage, Bulk Stations/Terminals: Breathing Loss, Jet Naphtha	TOTC2505	Total Energy		Other Petroleum	Regional
2501050180	Storage and Transport, Petroleum and Petroleum Product Storage, Bulk Stations/Terminals: Breathing Loss, Kerosene	TOTC2501	Total Energy		Kerosene	Regional
2501060000	Storage and Transport, Petroleum and Petroleum Product Storage, Gasoline Service Stations, Total: All Gasoline/All Processes	TRAN4001	Transportation		Motor Gasoline	Regional

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
2501060050	Storage and Transport, Petroleum and Petroleum Product Storage, Gasoline Service Stations, Stage 1: Total	TRAN4001	Transportation		Motor Gasoline	Regional
2501060051	Storage and Transport, Petroleum and Petroleum Product Storage, Gasoline Service Stations, Stage 1: Submerged Filling	TRAN4001	Transportation		Motor Gasoline	Regional
2501060052	Storage and Transport, Petroleum and Petroleum Product Storage, Gasoline Service Stations, Stage 1: Splash Filling	TRAN4001	Transportation		Motor Gasoline	Regional
2501060053	Storage and Transport, Petroleum and Petroleum Product Storage, Gasoline Service Stations, Stage 1: Balanced Submerged Filling	TRAN4001	Transportation		Motor Gasoline	Regional
2501060100	Storage and Transport, Petroleum and Petroleum Product Storage, Gasoline Service Stations, Stage 2: Total	TRAN4001	Transportation		Motor Gasoline	Regional
2501060101	Storage and Transport, Petroleum and Petroleum Product Storage, Gasoline Service Stations, Stage 2: Displacement Loss/Uncontrolled	TRAN4001	Transportation		Motor Gasoline	Regional
2501060102	Storage and Transport, Petroleum and Petroleum Product Storage, Gasoline Service Stations, Stage 2: Displacement Loss/Controlled	TRAN4001	Transportation		Motor Gasoline	Regional
2501060103	Storage and Transport, Petroleum and Petroleum Product Storage, Gasoline Service Stations, Stage 2: Spillage	TRAN4001	Transportation		Motor Gasoline	Regional
2501060200	Storage and Transport, Petroleum and Petroleum Product Storage, Gasoline Service Stations, Underground Tank: Total	TRAN4001	Transportation		Motor Gasoline	Regional
2501060201	Storage and Transport, Petroleum and Petroleum Product Storage, Gasoline Service Stations, Underground Tank: Breathing and Emptying	TRAN4001	Transportation		Motor Gasoline	Regional
2501070000	Storage and Transport, Petroleum and Petroleum Product Storage, Diesel Service Stations, Total: All Products/All Processes	TOTC2505	Total Energy		Other Petroleum	Regional
2501070051	Storage and Transport, Petroleum and Petroleum Product Storage, Diesel Service Stations, Stage 1: Submerged Filling	TOTC2505	Total Energy		Other Petroleum	Regional
2501070052	Storage and Transport, Petroleum and Petroleum Product Storage, Diesel Service Stations, Stage 1: Splash Filling	TOTC2505	Total Energy		Other Petroleum	Regional
2501070053	Storage and Transport : Petroleum and Petroleum Product Storage : Diesel Service Stations : Stage 1: Balanced Submerged Filling	TOTC2505	Total Energy		Other Petroleum	Regional
2501070100	Storage and Transport : Petroleum and Petroleum Product Storage : Diesel Service Stations : Stage 2: Total	TOTC2505	Total Energy		Other Petroleum	Regional
2501070101	Storage and Transport, Petroleum and Petroleum Product Storage, Diesel Service Stations, Stage 2: Displacement Loss/Uncontrolled	TOTC2505	Total Energy		Other Petroleum	Regional
2501070103	Storage and Transport, Petroleum and Petroleum Product Storage, Diesel Service Stations, Stage 2: Spillage	TOTC2505	Total Energy		Other Petroleum	Regional
2501070201	Storage and Transport, Petroleum and Petroleum Product Storage, Diesel Service Stations, Underground Tank: Breathing and Emptying	TOTC2505	Total Energy		Other Petroleum	Regional

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
2501080050	Storage and Transport : Petroleum and Petroleum Product Storage : Airports : Aviation Gasoline : Stage 1: Total	TOTC2505	Total Energy		Other Petroleum	Regional
2501080100	Storage and Transport : Petroleum and Petroleum Product Storage : Airports : Aviation Gasoline : Stage 2: Total	TOTC2505	Total Energy		Other Petroleum	Regional
2501995000	Storage and Transport, Petroleum and Petroleum Product Storage, All Storage Types: Working Loss, Total: All Products	PETS3001	Energy Production		Refined Petroleum Products	National
2501995030	Storage and Transport, Petroleum and Petroleum Product Storage, All Storage Types: Working Loss, Crude Oil	PETS3001	Energy Production		Refined Petroleum Products	National
2501995060	Storage and Transport, Petroleum and Petroleum Product Storage, All Storage Types: Working Loss, Residual Oil	TOTC2507	Total Energy		Residual Fuel	Regional
2501995090	Storage and Transport, Petroleum and Petroleum Product Storage, All Storage Types: Working Loss, Distillate Oil	TOTC2505	Total Energy		Other Petroleum	Regional
2501995120	Storage and Transport, Petroleum and Petroleum Product Storage, All Storage Types: Working Loss, Gasoline	TRAN4001	Transportation		Motor Gasoline	Regional
2501995150	Storage and Transport, Petroleum and Petroleum Product Storage, All Storage Types: Working Loss, Jet Naphtha	TRAN4002	Transportation		Jet Fuel	Regional
2501995180	Storage and Transport, Petroleum and Petroleum Product Storage, All Storage Types: Working Loss, Kerosene	TOTC2501	Total Energy		Kerosene	Regional
2505000000	Storage and Transport, Petroleum and Petroleum Product Transport, All Transport Types, Total: All Products	PETS3001	Energy Production		Refined Petroleum Products	National
2505010000	Storage and Transport : Petroleum and Petroleum Product Transport : Rail Tank Car : Total: All Products	PETS3001	Energy Production		Refined Petroleum Products	National
2505000120	Storage and Transport, Petroleum and Petroleum Product Transport, All Transport Types, Gasoline	TRAN4001	Transportation		Motor Gasoline	Regional
2505010000	Storage and Transport, Petroleum and Petroleum Product Transport, Rail Tank Car, Total: All Products	PETS3001	Energy Production		Refined Petroleum Products	National
2505010120	Storage and Transport, Petroleum and Petroleum Product Transport, Rail Tank Car, Gasoline	PETS3001	Energy Production		Refined Petroleum Products	National
2505020000	Storage and Transport, Petroleum and Petroleum Product Transport, Marine Vessel, Total: All Products	PETS3001	Energy Production		Refined Petroleum Products	National

			ANNUAL ENERGY OUTLOOK 2005 VARIABLE			
SCC	**SCC DESCRIPTION**	**INDICATOR CODE(S)**	**SECTOR(S)**	**SUBSECTOR(S)**	**FUEL TYPE**	**GEOGRAPHIC RESOLUTION**
2505020030	Storage and Transport, Petroleum and Petroleum Product Transport, Marine Vessel, Crude Oil	PETS3001	Energy Production		Refined Petroleum Products	National
2505020060	Storage and Transport, Petroleum and Petroleum Product Transport, Marine Vessel, Residual Oil	TOTC2507	Total Energy		Residual Fuel	Regional
2505020090	Storage and Transport, Petroleum and Petroleum Product Transport, Marine Vessel, Distillate Oil	TOTC2505	Total Energy		Other Petroleum	Regional
2505020120	Storage and Transport, Petroleum and Petroleum Product Transport, Marine Vessel, Gasoline	TRAN4001	Transportation		Motor Gasoline	Regional
2505020121	Storage and Transport : Petroleum and Petroleum Product Transport : Marine Vessel : Gasoline - Barge	TRAN4001	Transportation		Motor Gasoline	Regional
2505020150	Storage and Transport, Petroleum and Petroleum Product Transport, Marine Vessel, Jet Naphtha	TOTC2505	Total Energy		Other Petroleum	Regional
2505020180	Storage and Transport, Petroleum and Petroleum Product Transport, Marine Vessel, Kerosene	TOTC2501	Total Energy		Kerosene	Regional
2505020900	Storage and Transport, Petroleum and Petroleum Product Transport, Marine Vessel, Tank Cleaning	PETS3001	Energy Production		Refined Petroleum Products	National
2505030000	Storage and Transport, Petroleum and Petroleum Product Transport, Truck, Total: All Products	PETS3001	Energy Production		Refined Petroleum Products	National
2505030120	Storage and Transport, Petroleum and Petroleum Product Transport, Truck, Gasoline	TRAN4001	Transportation		Motor Gasoline	Regional
2505030180	Storage and Transport : Petroleum and Petroleum Product Transport : Truck : Kerosene	TOTC2501	Total Energy		Kerosene	Regional
2801520000	Miscellaneous Area Sources, Agriculture Production - Crops, Orchard Heaters, Total, all fuels	AGRC1004	Agriculture		Total Energy	National
2801520004	Miscellaneous Area Sources : Agriculture Production - Crops : Orchard Heaters : Diesel	AGRC1001	Agriculture		Distillate Oil	National
2801520010	Miscellaneous Area Sources : Agriculture Production - Crops : Orchard Heaters : Propane	AGRC1002	Agriculture		Liquified Petroleum Gas	National

SCC descriptions are blank if the reported SCC does not appear on EPA's official SCC list; these SCCs were assigned to AEO energy forecast variables based on the AEO assignments of closely related valid SCCs

APPENDIX H

EVALUATION OF NON-EGU POINT SOURCE AMMONIA EMISSION INVENTORIES

APPENDIX H | EVALUATION OF NON-EGU POINT SOURCE AMMONIA EMISSION INVENTORIES

The February 2006 draft of this report included a draft non-EGU point source ammonia (NH_3) inventory that included several apparent emissions anomalies. The anomalies suggested that the CAAA had a large deleterious effect on ammonia emissions in this category, and appeared to result from different methods used in the 1990 and 2002 versions of the Nationals Emissions Inventory (NEI). The 1990 NEI is used as the baseline for developing the "without 1990 Clean Air Act Amendments (CAAA)" case emissions estimates, while the 2002 NEI is used to represent 2000 year emissions for the "with 1990 CAAA" case. The Project Team therefore reviewed and evaluated these apparent anomalies. This appendix describes the Project Team's evaluation of the point source NH_3 emissions in each relevant source category, and a summary of changes made to the inventory to address major inconsistencies between the two inventories.

Evaluation of Emissions Estimates

Exhibit H-1 displays the large discrepancy between the 1990 and 2002 NEI point source NH_3 emission estimates.

Exhibit H-1. National 1990 and 2002 Point Source NH_3 Emissions

NEI Version	Point Source NH_3 Emissions (lbs)
1990	243,615
2002	931,996

The large point source emissions discrepancy appears to be associated with a small number of source categories (see Exhibit H-2).

Exhibit H-2. Comparison of 1990 and 2002 NH_3 Emission Estimates (lbs) for Select Source Categories

SCC	Description	1990	2002
50100701	Waste Disposal : Solid Waste Disposal - Government: Sewage Treatment: Entire Plant	0	254,345
10200902	External Combustion Boilers: Industrial: Wood/Bark Waste: Wood/Bark-fired Boiler	0	225,117
10200603	External Combustion Boilers: Industrial: Natural Gas: < 10 Million Btu/hr	124	141,610
10200907	External Combustion Boilers: Industrial: Wood/Bark Waste: Wood Cogeneration	0	49,232
30188801	Industrial Processes: Chemical Manufacturing: Fugitive Emissions: Specify in Comments	0	35,155
Subtotal		124	705,459

As indicated in Exhibit H-3, California facilities account for nearly all of the 2002 NH_3 emissions for these categories.

Exhibit H-3. National and California 2002 NH_3 Emission Estimates (lbs) for Select Categories

SCC	Description	California	Nation
50100701	Waste Disposal: Solid Waste Disposal - Government: Sewage Treatment: Entire Plant	252,711	254,345
10200902	External Combustion Boilers: Industrial: Wood/Bark Waste: Wood/Bark-fired Boiler	225,000	225,117
10200603	External Combustion Boilers: Industrial: Natural Gas: < 10 Million Btu/hr	141,450	141,610
10200907	External Combustion Boilers: Industrial: Wood/Bark Waste: Wood Cogeneration	49,200	49,232
30188801	Industrial Processes: Chemical Manufacturing: Fugitive Emissions: Specify in Comments	34,839	35,155
Subtotal		703,200	705,459

Exhibit H-4 presents California's 1990 and 2002 NEI emission estimates for the source categories of interest. This table suggests the use of inconsistent emission estimation methods between the two years.

Exhibit H-4. 1990 and 2002 California NH_3 Emission Estimates (lbs) for Select Categories

SCC	Description	1990	2002
50100701	Waste Disposal: Solid Waste Disposal - Government: Sewage Treatment: Entire Plant	0	252,711
10200902	External Combustion Boilers: Industrial: Wood/Bark Waste: Wood/Bark-fired Boiler	0	225,000
10200603	External Combustion Boilers: Industrial: Natural Gas: < 10 Million Btu/hr	31	141,450
10200907	External Combustion Boilers: Industrial: Wood/Bark Waste: Wood Cogeneration	0	49,200
30188801	Industrial Processes: Chemical Manufacturing: Fugitive Emissions: Specify in Comments	0	34,839
Subtotal		31	703,200

Given the large number of California NH_3 emission records associated with these source categories, it was not feasible for the Project Team to evaluate the emission estimates for each facility. However, we conducted a detailed review of emissions-related information for three facilities that account for more than 85 percent of California 2002 NH_3 emissions for the source categories of interest. These facilities are as follows:

- *Facility Name* - Regional Sanitation District; *State Facility Identifier* - 341624106; SCC 50100701 (Solid Waste Disposal-Government: Sewage Treatment: Entire Plant); *2002 annual NH_3 emissions* = 235,224 lbs; this facility appears (as Sacramento County Regional Sanitation District) in the 1990 NEI, but does not list the NH_3 emissions SCC reported in the 2002 NEI, nor any NH_3 emissions.

- *Facility Name* - Burney Forest Products; *State Facility Identifier* - 45162851; SCC 10200902 (External Combustion Boilers: Industrial: Wood/Bark Waste: Wood/Bark-fired Boiler); *2002 annual NH_3 emissions* = 225,000 lbs; this same facility appears (as Burney Mountain Power) in the 1990 NEI with a similar wood-fired boiler SCC (10200907), but without any NH_3 emissions.

- *Facility Name* - Celite Corporation; *State Facility Identifier* - 4211251735; SCC 10200603 (External Combustion Boilers: Industrial: Natural Gas: < 10 Million Btu/hr); *2002 annual NH_3 emissions* = 140,158 lbs; this same facility appears in the 1990 NEI with a similar natural gas-fired boiler SCC (10200602), but without any NH_3 emissions.

Because none of these facilities reported NH_3 emission controls, our review focused on determinations of whether the reported 2002 emission values are consistent with reported emission factor/activity values. Our evaluations included a review of EPA recommended emission factors for these SCCs and emission factor/activity data reported in the 2002 NEI and the California Emissions Inventory Development and Reporting System (CEIDARS). The Project Team also contacted California Air Resources Board (ARB) staff for additional information to support the validity of the 2002 NEI emission estimates.

REVIEW OF EMISSION FACTOR AND ACTIVITY ESTIMATES

Regional Sanitation District Facility

The 2002 NEI reports an emission factor value of "3.78" and an emission activity throughput value of "62,199" for the single NH_3 emissions record for this facility. Although the emission factor units and throughput units fields are blank for this record, the product of these two values approximates the reported NH_3 emissions value (235,224 lbs). CEIDARS indicates that the 62,199 value represents millions of gallons of wastewater. The Emissions Inventory Improvement (EIIP) guidance recommends an NH_3 emissions factor of 0.027 lbs per million gallons for this source category (Table II-5 of "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources," April 2004). When used with the reported throughput value, this emissions factor yields only 1,679.4 lbs of NH_3 emissions. Pechan contacted the ARB to request comment on these findings, and was told that the original NH_3 emissions estimate was developed from the results of an emissions source test performed at the plant.

Burney Forest Products Facility

The 2002 NEI reports an emissions activity throughput value of "187,345" for the NH_3 emissions record for this facility. The NEI does not report the units for this throughput value, nor an NH_3 emission factor. CEIDARS indicates throughput for the facility at 187,345 tons of wood/wood waste burned. By dividing the reported 2002 NEI emissions by this throughput value, one obtains an emission factor of 1.2 lbs of NH_3/ton burned. EIIP guidance suggests a NH_3 emissions factor for this SCC of 0.086 lb/ton (see Table III-1 of source noted above), which would yield an NH_3 emissions estimate of only 16,111.7 lbs. Pechan contacted the ARB to request comment on these findings, and was again told that the 2002 NH_3 emissions estimate was developed from facility emissions source tests.

Celite Corporation Facility

The 2002 NEI and CEIDARS do not report emissions factor or throughput values for any of the four Celite Corporation facility NH_3 emission records. Table III-1 of the EIIP guidance document noted above recommends an NH_3 emissions factor of 3.2 lbs/million cubic feet of natural gas burned. If this emissions factor was used to compute the 2002 NEI emissions estimate, then the Celite plant burned 43,799 million cubic feet of natural gas in boilers in 2002. The ARB was unable to confirm the validity of the NH_3 emission estimates for the four Celite facility records because the emission factor and amount of natural gas burned were designated as confidential by the local air pollution control district. Although ARB confirmation of the validity of the unusually high gas-fired boiler NH_3 emissions was not forthcoming, Pechan will accept the estimates because they were provided to ARB by the local air district. However, ammonia emissions this high should only occur if there is an air pollution control device with ammonia slip installed on these boilers.

Inventory Revisions

Although there are indications that some 2002 NEI point source NH_3 emission estimates in California are suspect, The Project Team does not believe that sufficient evidence exists to support revisions. Because the 1990 and 2002 NEI NH_3 emission estimation methods are clearly inconsistent for certain source categories, however, the Project Team added new NH_3 emission estimates for 1990 as follows:

1) Estimated 1990 emissions for the Regional Sanitation District facility for SCC 50100701 by applying a ratio of 136.9/170.4 to the 2002 estimates. The 136.9 value was the average day annual wastewater flow (in millions of gallons/day) for the facility in 1990 (from "2020 Master Plan: Final Draft Summary Report, Sacramento Regional Wastewater Treatment Plant," November 2001). The 170.4 value is the analogous 2992 value calculated by dividing reported 2002 annual throughput by 365 days.[9]

2) Assigned an NH_3 emission estimate of 225,000 lbs to the existing SCC 10200907 record in the 1990 NEI for the Burney Mountain Power facility (in lieu of any available information on 1990 facility throughput).

3) Assigned NH_3 emission estimates totaling 140,158 lbs to the existing four SCC 10200603 emission records in the 1990 NEI for the Celite Corporation plant (in lieu of any available information on 1990 facility throughput). The Project Team allocated these emissions to each record in proportion to their NO_X emission levels reported in the 1990 NEI.

4) Assigned the 2002 NEI 49,200 NH_3 emission estimate for SCC 10200907, which is associated with the facility "Wheelabrator Shasta E.C.I." in Shasta County,

[9] Note that the most current available value from the 2020 Master Plan document (2000 = 166.9 million gallons per day), is comparable to the calculated 2002 value.

California to the existing 1990 NEI Wheelabrator facility in Shasta County, which currently reports NH_3 emissions of 0.[10]

Exhibit H-5 summarizes the total national point source NH_3 emission estimates that resulted from implementing each of these recommendations.

Exhibit H-5. Revised Comparison of National 1990 and 2002 Point Source NH_3 Emissions

NEI Version	Point Source NH_3 Emissions (lbs)
1990	862,663
2002	931,996

[10] Note that the Project Team made no revisions to the 1990 NEI for SCC 30188801. The 2002 NEI identifies a single facility as responsible for all California NH_3 emissions for this SCC (Mojave Cogeneration). Pechan located NH_3 emissions for the same facility in the 1990 NEI (listed as "U.S. Borax & Chemical") under a natural gas boiler SCC (10200601). Available information indicates that the NH_3 emissions in both 1990 and 2002 result from application of selective catalytic reduction to control NOx emissions from the plant, and that the facility began operation in late July 1990.

APPENDIX I

8-HOUR OZONE NAAQS ANALYSIS FOR CALIFORNIA AREAS

APPENDIX I | 8-HOUR OZONE NAAQS ANALYSIS FOR CALIFORNIA AREAS

As described in Chapter 8, no modeling results were available from EPA for estimating the VOC and NO_x emission reduction targets for California areas not attaining the 8-hour ozone NAAQS. Alternate methods were needed for estimating the needed ozone precursor emission reductions and associated costs to meet the 8-hour ozone NAAQS in California nonattainment areas. A large fraction of the State is classified as being nonattainment for 8-hour ozone. The Project Team's emissions and cost analysis approach was to identify expected needed ozone precursor emission reductions by area for the areas that are classified as serious or severe, with the likelihood that these areas will have the highest expected compliance costs. California areas that are classified as either serious or severe ozone nonattainment are: Sacramento Metro (subpart 2 serious), San Joaquin Valley (subpart 2 serious), Riverside Co. (Coachella Valley) (subpart 2 serious), and Los Angeles-South Coast Air Basin (subpart 2 severe 17).[11]

The Project Team consulted publicly available information about each of these areas' 8-hour ozone modeling and/or draft implementation plans made and inquiries in cases where no information was posted. The information available for each area is described in this Appendix.

LOS ANGELES - SOUTHCOASTAIRBASIN

The draft 2007 plan for the South Coast Air Basin (SCAQMD, 2006) estimates the expected emission reductions that are needed from a 2002 baseline to both meet reasonable further progress (RFP) requirements and to attain the 8-hour ozone NAAQS. For reasonable progress, the SCAQMD is only required to provide for VOC and/or NO_x reductions of 3 percent per year from the 2002 baseline averaged over each consecutive 3 year period from 2008 to the Basin's attainment date of June 2017.

Exhibit I-1 shows the SCAQMD percentage reductions for both VOC and NO_x emissions necessary to meet the 3 percent requirement. Up until the year 2017, projected VOC baseline emissions are sufficient to meet the CAA requirements. For the milestone years 2017 and 2020, the baseline VOC emission levels are below the target levels. In 2017, VOC planned reductions from control measures in the draft SCAQMD plan are needed to show compliance with the targeted VOC thresholds. In 2020, the ozone carrying capacities require reduction target levels beyond the 3 percent per year goal, and are estimated to be 70.4 and 78.2 percent for VOC and NO_x, respectively. These values are

[11] This Appendix was derived from Appendix E of the parallel cost report for this analysis. The AirControlNET runs described in this Appendix were the source of both emissions and cost results for local controls assessed in the Second Prospective study.

used to estimate the emission reductions needed in the South Coast Air Basin in 2020 to meet the 8-hour ozone NAAQS.

Exhibit I-1. South Coast Air Basin Percent of VOC and NO_x Emission Reductions from the 2002 Baseline to Meet RFP Requirements

Year	VOC	NO_x	CAA*
2008	18.0	0.0	18.0
2011	27.0	0.0	27.0
2014	36.0	0.0	36.0
2017	45.0	0.0	45.0
2020	70.4	78.2	Attainment

* The percent VOC and NO_x reductions must equal the CAA percent reduction requirements listed here.

SAN JOAQUINVALLEY

The San Joaquin Valley Unified Air Pollution Control District has also performed modeling to estimate the additional VOC and NO_x emission reductions that will be needed in order to attain the 8-hour ozone NAAQS within this nonattainment area (SJVUAPCD, 2006). This modeling included various combinations of NO_x and VOC emission reductions. The combinations generate a data set of predicted ozone levels as a function of VOC and NO_x percentage reductions. The data is used as a carrying capacity diagram, which shows the level of emissions that the atmosphere can carry and still demonstrate attainment.

The SJVUAPCD carrying capacity diagrams show that approximately a 60 percent reduction in VOC and NO_x emissions from the 2012 baseline throughout the Central California modeling domain is needed to achieve the 8-hour average ozone NAAQS in the San Joaquin Valley. This amount of control is driven by the reductions needed to achieve the NAAQS near Arvin. Other sites are expected to reach attainment earlier, with fewer reductions needed. For instance, a 40 percent domain-wide reduction of 2012 VOC and NO_x emissions is needed to demonstrate attainment of the 8-hour ozone NAAQS at Parlier, the site downwind of Fresno in the central portion of the Valley with the worst air quality. Sites farther north, such as Merced, are expected to come into attainment with an approximate 20 percent NO_x and VOC reduction across the domain. This information was used by the Project Team to establish appropriate needed emission reductions by county for the different sub-areas within the San Joaquin Valley.

SACRAMENTO METRO

The Sacramento Metro region has used air quality modeling results for 2012, 2018, and 2023 to see if existing controls would result in 8-hour ozone NAAQS attainment, and if not, to estimate what combinations of VOC and NO_x control might be used to reach attainment (SMAQMD, 2006). The 2012 air quality modeling analysis for the peak monitoring site in the Sacramento region indicates that the federal 8-hour ozone standard could be attained by reducing 2012 emissions of VOC and NO_x by approximately 27 percent each. Reducing the 2012 projected emissions by 27 percent yields emissions targets for the Sacramento nonattainment area of about 95 tons per day (tpd) of VOC and 86 tpd of NO_x, representing additional reductions of 35 tpd and 32 tpd, respectively. Exhibit I-2 summarizes the attainment targets and emission reductions needed in the

Sacramento area to attain the 8-hour ozone NAAQS in 2012. The ozone modeling analysis indicates that other combinations of VOC and NO_x reductions may be possible to bring the area into attainment as well.

Exhibit I-2. Summary of Attainment Targets and Emission Reductions Needed in the Sacramento Nonattainment Area for 2012

Sacramento Nonattainment Area	VOC (tpd)	NO_x (tpd)
2002 Baseline Emissions	168	176
2012 Emissions Forecast	130	118
Additional percent reduction required	27%	27%
2012 Attainment Targets	95	86
2012 Emission Reductions Needed	35	32

The 2018 modeling analysis for the Sacramento region indicates that the 8-hour ozone NAAQS could be attained by reducing 2018 emissions of VOC and NO_x by 10 percent each. Therefore, the 2018 attainment targets for the Sacramento nonattainment area are about 107 tpd of VOC and 78 tpd of NO_x, representing additional reductions of 12 tpd of VOC and 9 tpd of NO_x. Exhibit I-3 summarizes the attainment targets and emission reductions needed in the Sacramento area to attain the 8-hour ozone NAAQS in 2018. In addition to the attainment control strategy of equal percentage reductions from both VOC and NO_x emissions, the ozone modeling analysis indicates that other combinations of VOC and NO_x emission reductions may be possible for attainment as well.

Exhibit I-3. Summary of Attainment Targets and Emission Reductions Needed in the Sacramento Nonattainment Area for 2018

Sacramento Nonattainment Area	VOC (tpd)	NO_x (tpd)
2002 Baseline Emissions	168	176
2018 Emissions Forecast	119	87
Additional percent reduction required	10%	10%
2018 Attainment Targets	107	78
2018 Emission Reductions Needed	12	9

RIVERSIDE COUNTY - COACHELLA VALLEY

The Coachella Valley 8-hour ozone nonattainment area is a sub region of Riverside County that is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. This is a desert area that is impacted by pollutant transport from the South Coast Air Basin. Within the state of California, the Coachella Valley Planning Area is under the purview of the South Coast Air Quality Management District. Plans for meeting the 8-hour ozone standard for the Coachella Valley Planning Area are not addressed in the Draft 2007 AQMP (SCAQMD, 2006). Therefore, no specific attainment targets are available now for this nonattainment area. Given the likelihood that the air quality plan for Coachella Valley will rely on reducing South Coast Air Basin emissions, and resulting transport, this portion of Riverside County was not modeled separately from the rest of the South Coast. Because the area and mobile source emissions within the Coachella Valley area are difficult to identify separately (they are computed and stored as county-level estimates in the emission inventory), they were incorporated into the analysis of the South Coast Air Basin.

MARGINAL AREAS

When contacted, the Bay Area AQMD confirmed that it is reasonable for us to exclude marginal 8-hour ozone nonattainment areas from the analysis of California's compliance with the NAAQS. They reported that they are not required to conduct modeling for 8-hour ozone NAAQS attainment but instead need only to show continued progress toward attainment (Vintze, 2006). Accordingly, they have no plans to adopt control measures beyond those required by their implementation plan for the 1-hour Ozone NAAQS.

TARGET EMISSIONS REDUCTIONS FOR 8-HOUR OZONE COMPLIANCE

Exhibit I-4 summarizes the needed ozone precursor emission reductions for each California area included in this analysis in terms of the compliance year closest to the 2010 and 2020 analysis years used in this section 812 analysis. For each area, the needed emission reduction percentages are expressed in relation to either 2002 or a projection year's emissions. The emission reduction targets for the San Joaquin Valley are presented separately for each of the three sub-areas within the larger ozone nonattainment area. The text and tables below describe how the emission reduction percentages in Exhibit I-4 were translated into effective emission reduction targets in 2010 and 2020 by area.

Exhibit I-4. Percentage Target Reductions for California 8-Hour Ozone Nonattainment Areas

Nonattainment Area	2010 NO_x Target (%)	2010 VOC Target (%)	2020 NO_x Target (%)	2020 VOC Target (%)
Central San Joaquin Valley, CA	40 (from 2012 baseline)	40 (from 2012 baseline)	40 (from 2012 baseline)	40 (from 2012 baseline)
Los Angeles, CA	-	24 (RFP requirement)	78.2 (from 2002 baseline)	70.4 (from 2002 baseline)
Northern San Joaquin Valley, CA	20 (from 2012 baseline)	20 (from 2012 baseline)	20 (from 2012 baseline)	20 (from 2012 baseline)
Sacramento, CA	27 (from 2012 baseline)	27 (from 2012 baseline)	10 (from 2018 baseline)	10 (from 2018 baseline)
Southern San Joaquin Valley, CA	60 (from 2012 baseline)	60 (from 2012 baseline)	60 (from 2012 baseline)	60 (from 2012 baseline)

The AirControlNET model that is used to estimate direct compliance costs uses absolute target tons in the least cost analysis for selecting local control measures to attain the 8-hour ozone NAAQS. In order to calculate absolute reduction target tons for some of these areas, 2012 and 2018 emissions were needed. The estimated 2012 and 2018 emissions were calculated by interpolating from the 2010 and 2020 core scenario emissions inventories for each geographic area of interest. Tables E-5 and E-6 show these steps.

Exhibit I-5 provides NO_x and VOC emissions for the with CAAA scenario for each of these nonattainment areas for the years - 2002, 2010 and 2020.

Exhibit I-5. 2002, 2010, and 2020 Core Scenario Emissions Estimates for California 8-Hour Ozone Nonattainment Areas

Nonattainment Area	2002 NO_x Annual Emissions	2002 VOC Annual Emissions	2010 NO_x Annual Emissions	2010 VOC Annual Emissions	2020 NO_x Annual Emissions	2020 VOC Annual Emissions
Central San Joaquin Valley, CA	75,074	64,913	54,700	60,925	39,598	63,773
Los Angeles, CA	508,635	359,867	398,441	276,934	293,043	272,870
Northern San Joaquin Valley, CA	64,398	49,787	40,685	42,177	29,490	43,970
Sacramento, CA	84,143	69,275	67,580	58,642	48,096	57,351
Southern San Joaquin Valley, CA	62,127	39,523	52,320	31,913	50,891	31,447

n was performed using following formula.

$$\alpha = \frac{x - x_0}{x_1 - x_0}.$$

$$y = y_0 + \alpha(y_1 - y_0)$$

Where:

X	=	Year that we want to interpolate
X_0	=	Year 2010
X_1	=	Year 2020
Y	=	Emissions for the interpolated year X
Y_0	=	2010 Emissions
Y_1	=	2020 Emissions

So 2012 NO_x and VOC emissions was calculated using following formula:

α = (2012 - 2010) / (2020 - 2010) = 0.2

2012 Emissions = 2010 Emissions + (0.2) x (2020 Emissions - 2010 Emissions)

Similarly 2018 emissions was calculated using:

α = (2018 - 2010) / (2020 - 2010) = 0.8

2018 Emissions = 2010 Emissions + (0.8) x (2020 Emissions - 2010 Emissions)

Exhibit I-6 provides interpolated 2012 and 2018 NO_x and VOC emissions for each nonattainment areas.

Exhibit I-6. Estimated 2012 and 2018 Emissions for California 8-Hour Ozone Nonattainment Areas

Nonattainment Area	2012 NO_x Annual Emissions	2012 VOC Annual Emissions	2018 NO_x Annual Emissions	2018 VOC Annual Emissions
Central San Joaquin Valley, CA	51,680	61,495	42,619	63,204
Los Angeles, CA	377,361	276,121	314,123	273,683
Northern San Joaquin Valley, CA	38,446	42,536	31,729	43,611
Sacramento, CA	63,684	58,384	51,993	57,609
Southern San Joaquin Valley, CA	52,034	31,820	51,177	31,541

Absolute target reduction tons required to attain 8-hour ozone NAAQS were calculated by subtracting required attainment emissions, calculated using percentage reduction targets, from total emissions.

So for 2010,

2010 Target Reduction = 2010 Total Emissions - (Baseline Year Emissions x (1 - % Target Reduction))

Similarly for 2020,

2020 Target Reduction = 2020 Total Emissions - (Baseline Year Emissions x (1 - % Target Reduction))

These are the absolute target tons that AirControlNET uses to select local control measures on least cost basis. These calculated absolute target tons are provided in Exhibit I-7.

Exhibit I-7. Absolute Target Tons Required to Attain the 8-Hour Ozone NAAQS in California Nonattainment Areas

Nonattainment Area	2010 NO_x Target Reductions	2010 VOC Target Reductions	2020 NO_x Target Reductions	2020 VOC Target Reductions
Central San Joaquin Valley, CA	23,692	24,028	8,591	26,877
Los Angeles, CA	-	3,436	182,161	166,349
Northern San Joaquin Valley, CA	9,928	8,149	(1,267)	9,941
Sacramento, CA	21,091	16,022	1,303	5,503
Southern San Joaquin Valley, CA	31,506	19,185	30,077	18,719

For these serious or severe California nonattainment areas, it was assumed that RACT was already applied in the base inventory. So no further RACT controls were simulated as mandatory measures for these nonattainment areas.

I/M controls were then applied to counties where required. Once I/M and RACT controls were applied, the costs of meeting the additional emission reduction requirements were determined for each area by using control techniques, efficiencies, and cost databases in concert with the incremental emission reduction and progress requirements listed in Exhibit I-7. For additional local controls, a least-cost algorithm was used to identify and apply the control measures to meet the progress requirements, where applicable. First, the potential sources of emission and reductions and their costs were identified. Next, the lowest cost, second lowest, third lowest, and so forth, control measures were selected until the progress requirement or attainment target was met. Because of the discrete nature of control measures and their efficiencies, sometimes the emission reduction or progress target was exceeded. Any excess might be used as an offset against new source growth emissions, if the excess were significant.

Similarly, if an area required additional reductions to meet their emission reduction target for NO_x and/or VOC, source/controls within 100 km radius for VOC reductions and within 200 km radius for NO_x reductions were selected on a least cost basis, as described above.

AirControlNET Modeling Results and Comparison of Target to Modeled Emissions Reductions

Exhibit I-8 summarizes estimated nonattainment area-level and state-level 8-hour ozone NAAQS emissions reductions for 2010. Note that the modeled VOC and NO_x emission reductions for Central San Joaquin Valley were not sufficient to meet attainment. The residual tons column in Exhibit I-8 provides the shortfall reductions.

As is the case for the Local Control Measures Analysis provided in Chapter 8 for non-California areas, control measures for each nonattainment area in California were selected from sources located within the nonattainment area and within a 100 km buffer for VOC control measures and within a 200 km buffer for NO_x control measures. Control measures were selected on a least-cost basis to meet their emission reduction target for NO_x and VOC. Because of the close proximity of these nonattainment areas, the 100 and/or 200 km buffer areas sometimes overlap. In these cases, and because nonattainment areas were analyzed independently, the possibility exists that a source/control measure combination could be selected more than once to satisfy reduction requirements of more than one area. Any double counting of cost and reductions is expected to be small in most of these areas.

Exhibit I-9 summarizes the results of the California area 8-hour ozone NAAQS analysis for 2020. Year 2020 shows a significant increase in the amount of residual tons to be met by unidentified measures because sufficient control measures are not available to meet the very large emission reductions required in the South Coast Air Basin (Los Angeles) to attain the 8-hour ozone NAAQS in 2020.

Comparing the 2020 and 2010 emissions analysis summaries for the individual nonattainment areas shows that the required local reductions for the SJV and Sacramento areas are considerably lower in 2020 than in 2010. This occurs because the core scenarios (Federal and State rules) are expected to produce continuing emission reductions between 2010 and 2020, so the needed emission reductions to reach attainment emission levels in 2020 are lower than in 2010. A significant part of these 2010 to 2020 emission reductions for VOC and NO_x are achieved by emission and fuel standards applied to onroad vehicles and nonroad engines/vehicles.

Exhibit I-8. 8-Hour Ozone NAAQS Emissions Analysis Summary for California Areas (2010)

Nonattainment Area	VOC Tons Reduced from Core Scenario	NO_x Tons Reduced from Core Scenario	Residual VOC tons	Residual NO_x tons
Central San Joaquin Valley, CA	14,073	15,860	9,955	7,832
Los Angeles, CA	3,611	-	-	-
Northern San Joaquin Valley, CA	8,165	11,107	-	-
Sacramento, CA	16,252	21,152	-	-
Southern San Joaquin Valley, CA	19,456	31,608	-	-
Totals	**61,557**	**79,727**	**9,955**	**7,832**

Exhibit I-9. 8-Hour Ozone NAAQS Emissions Analysis Summary for California Areas (2020)

Nonattainment Area	VOC Tons Reduced from Core Scenario	NO_x Tons Reduced from Core Scenario	Residual VOC tons	Residual NO_x tons
Central San Joaquin Valley, CA	15,880	9,889	10,997	-
Los Angeles, CA	37,529	39,843	128,820	142,318
Northern San Joaquin Valley, CA	9,948	-	-	-
Sacramento, CA	5,517	1,634	-	-
Southern San Joaquin Valley, CA	18,740	30,319	-	-
Totals	**87,613**	**81,685**	**139,818**	**142,318**

REFERENCES

SCAQMD, 2006: South Coast Air Quality Management District, "Draft 2007 Air Quality Management Plan (AQMP)." 2006. http://www.aqmd.gov/aqmp/07aqmp/07AQMP.html

SJVUAPCD, 2006: San Joaquin Valley Unified Air Pollution Control District, "2007 Ozone Plan," (Draft) October 17, 2006. www.valleyair.org

SMAQMD, 2006: Sacramento Metropolitan Air Quality Management District, "Sacramento Regional 8-Hour Ozone Attainment Plan - Proposed Control Measures (Draft)," Sacramento, CA. October 2006.

Vintze, 2006: Personal Communication, David Vintze, Bay Area Air Quality Management District, San Francisco, CA with J. Wilson, E.H. Pechan& Associates, Inc., Springfield, VA. December 2006.

APPENDIX J

DOCUMENTATION OF PM AUGMENTATION PROCEDURES FOR POINT AND AREA SOURCE INVENTORIES

APPENDIX J | DOCUMENTATION OF PM AUGMENTATION PROCEDURES FOR POINT AND AREA SOURCE INVENTORIES

The PM_{10} and $PM_{2.5}$ emissions in the 1990 NEI point and area source inventories are for filterable emissions only. The 1990 NEI is used as the basis for the without-CAAA scenario in this analysis. Beginning with Version 3 of the final 1999 National Emission Inventory point and area source files, EPA began adding condensible PM emissions associated with fuel combustion sources to the inventories. As a result, EPA adopted the following nomenclature for recording PM emissions in inventories:

- PM10-PRI = Primary PM_{10} (i.e., PM10-FIL + PM-CON)
- PM25-PRI = Primary $PM_{2.5}$ (i.e., PM25-FIL + PM-CON)
- PM10-FIL = Filterable PM_{10}
- PM25-FIL = Filterable $PM_{2.5}$
- PM-CON = condensible PM

This appendix documents the methods and data sources used to augment the 1990 point and area source inventories for Section 812 to add PM-CON, PM10-PRI, and PM25-PRI emissions for fuel combustion sources. In addition, this appendix documents methods applied to resolve some QA issues identified for non-fuel combustion source filterable emissions in the 1990 area source Section 812 inventory.

INVENTORY FILE PREPARATION

The existing PM emissions in the point and area source inventories are filterable emissions. These emissions were preserved; however, the field names were changed to designate the emissions as filterable. Then, three additional fields were added to the inventory file to hold PM-CON, PM10-PRI, and PM25-PRI emissions. Exhibit J-1 shows the old and new field names for the filterable emissions and the new field names for the primary and condensible emissions. Note that the area source inventory file did not contain any fields for daily emissions; therefore, it was not necessary to change the name of or add new fields for daily PM emissions.

Exhibit J-1. Definition of Field Names for Holding PM Emissions in the 1990 Section 812 Point and Area Source Inventory Database Files

Old Field Name	New Field Name	Notes
Annual Emissions		
PM10_ANN	PM10FIL_ANN	Previous emissions were classified as filterable for all SCCs
PM25_ANN	PM25FIL_ANN	Previous emissions were classified as filterable for all SCCs
	PM10PRI_ANN	New field added to hold PM10-PRI annual emissions
	PM25PRI_ANN	New field added to hold PM25-PRI annual emissions
	PMCON_ANN	New field added to hold PM-CON annual emissions
Daily Emissions for Point Source Inventory*		
PM10_OSD	PM10FIL_OSD	Previous emissions were classified as filterable for all SCCs
PM25_OSD	PM25FIL_OSD	Previous emissions were classified as filterable for all SCCs
	PM10PRI_ OSD	New field added to hold PM10-PRI daily emissions
	PM25PRI_ OSD	New field added to hold PM25-PRI daily emissions
	PMCON_ OSD	New field added to hold PM-CON daily emissions

* The area source inventory file did not contain any fields for daily emissions.

Review of the PM annual and daily emission fields in the 1990 point and area source inventories identified null values. The null values were changed to zero in order to electronically apply the augmentation procedures.

METHODS AND DATA SOURCES

ADDITION OF CONDENSIBLE EMISSIONS FOR FUEL COMBUSTION SOURCES

Condensible emissions were added to the Section 812 inventories for external and internal stationary fuel combustion sources in the point (i.e., SCCs starting with 10 or 20) and area (i.e., SCCs starting with 21) source inventories. The methods applied were those used by EPA to augment Version 3 of the final 1999 NEI and the July 2006 version of the final 2002 NEI.[12] These methods involved the use of emission factor ratios to calculate PM10-PRI emissions from PM10-FIL emissions. PM-CON emissions were calculated by subtracting PM10-FIL emissions from the PM10-PRI emissions. The PM-CON emissions were then added to the PM25-FIL emissions to obtain PM25-PRI emissions. This approach was used to ensure that the PM-CON mass was the same in the PM10-PRI and PM25-PRI emissions. These calculations were performed for each record in the point and area source inventories by matching SCCs in the inventories to the SCCs in the ratio file.

The ratio file for point sources was obtained from EPA's website documenting the methods for the 2002 NEI.[1] This file was compared to the 1990 inventory to identify SCCs in the inventory that were not in EPA's ratio file. Then, ratios were assigned to the SCCs based on the ratios that existed in EPA's ratio file for similar emission sources.[13]The ratio dataset developed by the Project Team provides the SCC, SCC

[12]The documentation for the July 2006 version of the final 2002 point and nonpointNEI is available at the following website: http://www.epa.gov/ttn/chief/net/2002inventory.html. The name of the point source ratio file obtained from this reference is "PM augmentation ratios.xls".

[13] The point source ratio dataset developed by the Project Team is documented in an Excel file named "PM Ratios for 1990 Section 812.xls", available on request. The ratios applied to the 1990 area source inventory are also included in this file.

description, and PM10-FIL/PM10-PRI ratio. In addition, the spreadsheet contains a "Map To SCC" column and a "Notes" column. For the SCCs in the 1990 inventory but not in EPA's original ratio file, the SCC for which a ratio was available is entered in this column and the "Notes" column is filled in if necessary to provide further explanation of the assumptions used to assign ratios to the SCCs not in EPA's original ratio file.

For augmentation of the 1990 area source inventory, the EPA has not developed a consolidated ratio file as it has for the point source NEI. Therefore, a consolidated ratio file was developed using the uncontrolled emission factors used to estimate PM10-FIL and PM10-PRI emissions for the final 2002 NEI. The emission factors are available in Appendix C (Access database format) of the documentation for the final 2002 nonpointNEI. Note that for both the point and area source inventories, uncontrolled PM10-FIL emissions were not back-calculated for controlled sources before applying the ratios to calculate PM10-PRI emissions. The EPA developed the ratios using uncontrolled emission factors available in AP-42 and the Factor Information Retrieval (FIRE) system database. Technology transfer was used to assign ratios to emission sources for which emission factors did not exist using the ratios developed from available emission factors for similar emission sources. When the PM augmentation procedures were developed by EPA, it was determined that application of the ratios to back-calculated uncontrolled filterable emissions using the reported control efficiencies for controlled sources resulted in significantly overestimating primary and condensible emissions. Therefore, EPA decided to apply the ratios to controlled emissions even though the ratios were developed from uncontrolled emission factors because this approach provided more realistic estimates. Thus, this methodology was also followed during the augmentation of the 1990 Section 812 point and area source inventories.

ADJUSTMENT OF PM EMISSIONS FOR NATURAL GAS COMBUSTION

For the July 2006 version of the final point and nonpointNEI, EPA adjusted the PM emissions for point and area source external and internal natural gas and Liquified petroleum gas (LPG) combustion sources by about 95%. The reason for this adjustment is that EPA believes that the AP-42 emission factors for condensable emissions are too high. The EPA based this adjustment on some limited data from the draft EPA dilution method that is similar to Conditional Test Method (CTM) 39 (http://www.epa.gov/ttn/emc/ctm.html) that measures PM10-PRI and PM2.5-PRI directly. The data that this adjustment is based on can be found at:http://www.nyserda.org/programs/Environment/emepreports.asp#FineParticulates.

The PM emissions for natural gas and LPG sources in the Section 812 1990 area source inventory were adjusted using the EPA methods. Note that these factors were also applied to the natural gas and LPG external and internal combustion SCCs in the version of the 2002 NEI that is being used for Section 812. Table 2 identifies the area source SCCs and PM adjustment factors applied to the 1990 area source inventory for Section 812. Exhibit J-2 lists only the SCCs that exist in the 1990 inventory and not the full list to which EPA applied adjustment factors in the final 2002 nonpointNEI. To ensure that the filterable emissions did not exceed the primary emissions, the PM10-FIL emissions were recalculated by subtracting PM-CON emissions from the PM10-PRI emissions and the PM25-FIL emissions were recalculated by subtracting PM-CON emissions from the PM25-PRI emissions.

PM AUGMENTATION FOR NON-FUEL COMBUSTION SOURCES

For non-fuel combustion sources (i.e., sources not included in the augmentation to add condensible emissions previously discussed), PM10-PRI emissions were set equal to PM10-FIL emissions and PM25-PRI emissions were set equal to PM25-FIL emissions. Condensible emissions were set equal to zero in the inventory.

As a result of running QA checks after completing the PM augmentation for the 1990 point and area source inventories, records were identified in the area source inventory where the PM25-FIL emissions exceeded the PM10-FIL emissions. Exhibit J-3 lists the state, county, SCC, and emissions for which this issue occurred. To correct this issue, the PM25-FIL/PRI emissions were set equal to the PM10-FIL/PRI emissions.

Exhibit J-2. Adjustments to PM Emissions for Natural Gas and LPG Stationary Source Fuel Combustion

SCC	SCC Description	PM10-PRI Factor	PM25-PRI Factor	PM-CON Factor
2102006000	Stationary Source Fuel Combustion : Industrial : Natural Gas : Total: Boilers and IC Engines	0.068	0.057	0.057
2102006001	Stationary Source Fuel Combustion : Industrial : Natural Gas : All Boiler Types	0.068	0.057	0.057
2102006002	Stationary Source Fuel Combustion : Industrial : Natural Gas : All IC Engine Types	0.068	0.057	0.057
2102007000	Stationary Source Fuel Combustion : Industrial : Liquified Petroleum Gas (LPG) : Total: All Boiler Types	0.068	0.057	0.057
2103006000	Stationary Source Fuel Combustion : Commercial/Institutional : Natural Gas : Total: Boilers and IC Engines	0.068	0.057	0.057
2103007000	Stationary Source Fuel Combustion : Commercial/Institutional : Liquified Petroleum Gas (LPG) : Total: All Combustor Types	0.068	0.057	0.057
2104006000	Stationary Source Fuel Combustion : Residential : Natural Gas : Total: All Combustor Types	0.068	0.057	0.057
2104007000	Stationary Source Fuel Combustion : Residential : Liquified Petroleum Gas (LPG) : Total: All Combustor Types	0.068	0.057	0.057
2199007000	Stationary Source Fuel Combustion : Total Area Source Fuel Combustion : Liquified Petroleum Gas (LPG) : Total: All Boiler Types	0.068	0.057	0.057

Exhibit J-3. Records in the 1990 Area Source Inventory with PM10-FIL/PRI Emissions Less than PM25-FIL/PRI Emissions

State FIPS	County FIPS	SCC	SCC Description	PM10-PRI Annual (Tons)	PM10- FIL Annual (Tons)	PM25-PRI Annual (Tons)	PM25-FIL Annual (Tons)	PM-CON Annual (Tons)	PM10-FIL minus PM25-FIL Annual (Tons)
27	003	2285002008	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Passenger Trains (Amtrak)	0.2999	0.2999	0.4892	0.4892	0	-0.1893
27	003	2285002010	Mobile Sources : Railroad Equipment : Diesel : Yard Locomotives	0.418	0.418	4.6691	4.6691	0	-4.2511
27	005	2285002008	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Passenger Trains (Amtrak)	0.2999	0.2999	0.7377	0.7377	0	-0.4378
27	007	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	2.4284	2.4284	3.217	3.217	0	-0.7886
27	009	2285002008	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Passenger Trains (Amtrak)	0.2999	0.2999	0.6146	0.6146	0	-0.3147
27	011	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	0.8136	0.8136	1.2865	1.2865	0	-0.4729
27	019	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	0.0277	0.0277	0.0289	0.0289	0	-0.0012
27	027	2285002008	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Passenger Trains (Amtrak)	0.2999	0.2999	0.8518	0.8518	0	-0.5519
27	029	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	2.2001	2.2001	2.6709	2.6709	0	-0.4708
27	037	2285002010	Mobile Sources : Railroad Equipment : Diesel : Yard Locomotives	1.254	1.254	2.808	2.808	0	-1.554
27	049	2285002008	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Passenger Trains (Amtrak)	0.2999	0.2999	0.3759	0.3759	0	-0.076
27	053	2285002010	Mobile Sources : Railroad Equipment : Diesel : Yard Locomotives	5.4572	5.4572	7.1272	7.1272	0	-1.67
27	055	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	0.6417	0.6417	3.6877	3.6877	0	-3.046
27	065	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	1.1007	1.1007	4.5424	4.5424	0	-3.4417
27	073	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	0.8633	0.8633	1.3024	1.3024	0	-0.4391
27	081	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	0.5007	0.5007	2.1253	2.1253	0	-1.6246
27	087	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	2.9659	2.9659	3.9927	3.9927	0	-1.0268
27	093	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	8.1586	8.1586	13.4624	13.4624	0	-5.3038
27	097	2285002008	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Passenger Trains (Amtrak)	0.2999	0.2999	1.1538	1.1538	0	-0.8539
27	107	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	0.0295	0.0295	0.1592	0.1592	0	-0.1297
27	111	2285002008	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Passenger Trains (Amtrak)	0.2999	0.2999	0.8163	0.8163	0	-0.5164
27	113	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	1.7456	1.7456	2.5324	2.5324	0	-0.7868
27	131	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	3.0439	3.0439	3.1707	3.1707	0	-0.1268

State FIPS	County FIPS	SCC	SCC Description	PM10-PRI Annual (Tons)	PM10- FIL Annual (Tons)	PM25-PRI Annual (Tons)	PM25-FIL Annual (Tons)	PM-CON Annual (Tons)	PM10-FIL minus PM25-FIL Annual (Tons)
27	131	2285002007	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class II / III Operations	2.0666	2.0666	4.8036	4.8036	0	-2.737
27	141	2285002010	Mobile Sources : Railroad Equipment : Diesel : Yard Locomotives	0.418	0.418	4.5645	4.5645	0	-4.1465
27	145	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	7.3193	7.3193	15.8415	15.8415	0	-8.5222
27	153	2285002008	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Passenger Trains (Amtrak)	0.2999	0.2999	0.9026	0.9026	0	-0.6027
27	157	2285002008	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Passenger Trains (Amtrak)	0.2999	0.2999	0.6261	0.6261	0	-0.3262
27	159	2285002008	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Passenger Trains (Amtrak)	0.2999	0.2999	0.7351	0.7351	0	-0.4352
27	163	2285002010	Mobile Sources : Railroad Equipment : Diesel : Yard Locomotives	0.836	0.836	5.133	5.133	0	-4.297
27	169	2285002008	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Passenger Trains (Amtrak)	0.2999	0.2999	0.6077	0.6077	0	-0.3078
44	003	2275001000	Mobile Sources : Aircraft : Military Aircraft : Total	0	0	0.2691	0.2691	0	-0.2691
44	003	2275020000	Mobile Sources : Aircraft : Commercial Aircraft : Total: All Types	0	0	16.707	16.707	0	-16.707
44	003	2275050000	Mobile Sources : Aircraft : General Aviation : Total	0	0	1.8567	1.8567	0	-1.8567
44	003	2275060000	Mobile Sources : Aircraft : Air Taxi : Total	0	0	4.1884	4.1884	0	-4.1884
44	005	2275050000	Mobile Sources : Aircraft : General Aviation : Total	0	0	0.5277	0.5277	0	-0.5277
44	005	2285002006	Mobile Sources : Railroad Equipment : Diesel : Line Haul Locomotives: Class I Operations	0	0	0.0184	0.0184	0	-0.0184
44	005	2285002010	Mobile Sources : Railroad Equipment : Diesel : Yard Locomotives	0	0	0.0074	0.0074	0	-0.0074
44	007	2275001000	Mobile Sources : Aircraft : Military Aircraft : Total	0	0	0.0056	0.0056	0	-0.0056
44	007	2275050000	Mobile Sources : Aircraft : General Aviation : Total	0	0	2.346	2.346	0	-2.346
44	007	2275060000	Mobile Sources : Aircraft : Air Taxi : Total	0	0	0.3122	0.3122	0	-0.3122
44	007	2280002100	Mobile Sources : Marine Vessels, Commercial : Diesel : Port emissions	0.05	0.05	77.8859	77.8859	0	-77.8359
44	009	2275001000	Mobile Sources : Aircraft : Military Aircraft : Total	0	0	0.7587	0.7587	0	-0.7587
44	009	2275020000	Mobile Sources : Aircraft : Commercial Aircraft : Total: All Types	0	0	0.8752	0.8752	0	-0.8752
44	009	2275050000	Mobile Sources : Aircraft : General Aviation : Total	0	0	1.1248	1.1248	0	-1.1248
44	009	2275060000	Mobile Sources : Aircraft : Air Taxi : Total	0	0	0.031	0.031	0	-0.031

APPENDIX K

WILDLAND FIRE AND PRESCRIBED BURNING ACTIVITY AND EMISSIONS

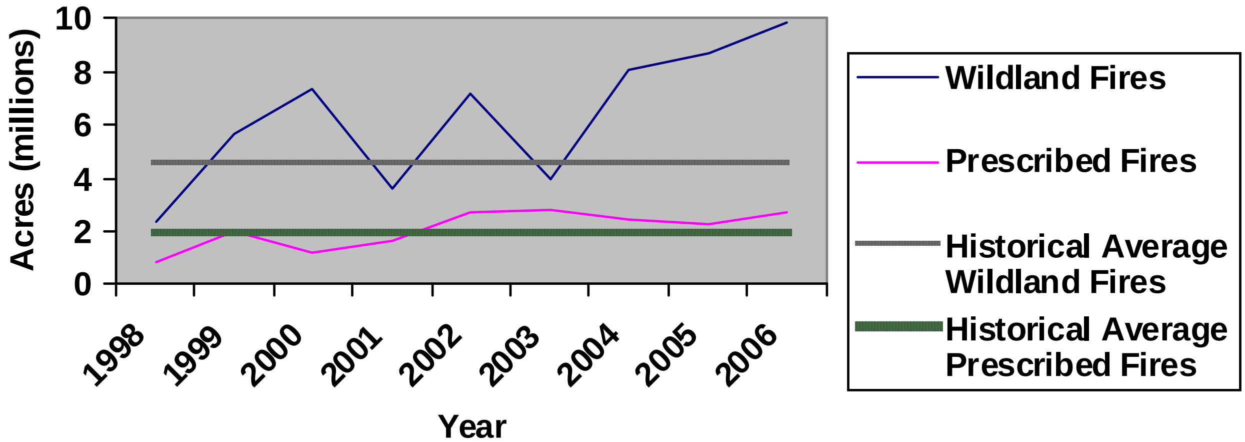
APPENDIX K | WILDLAND FIRE AND PRESCRIBED BURNING ACTIVITY AND EMISSIONS

The second section 812 Prospective analysis uses estimates of historical average wildland fire emissions and prescribed fire emissions as the estimates for all analysis years (1990, 2000, 2010 and 2020). This assumption is consistent with how EPA handled these source types in the recent CAIR analysis, and it keeps this activity from being a variable in the projections and from producing differences between the with versus without CAAA scenarios. For wildfires, emissions are estimated using the national average acres burned during the period 1990 to 2003. For prescribed fire, the historical average was estimated based on acres burned from 1996 to 2003.

The above assumptions differ somewhat from what was assumed in the First Prospective study. At the time that the First Prospective study was performed, information obtained from EPA and other federal agencies suggested that federal prescribed burning activity on public lands would increase significantly from 1990 to 2000, and again by 2010 to reflect increases in federal activity. In acreage terms, the total burned acres were expected to be 5,078 thousand in 1990, 6,404 thousand in 2000, and 8,987 thousand by 2010. For wildfires, although some studies suggested that increases in prescribed burns would decrease wildfire occurrences and emissions, it was conservatively assumed that wildfire emissions in 2000 and 2010 would be the same as in 1990. This assumption was made because significant decreases in wildfire emissions might not be realized until a prescribed burning program had been in place for some time.

Exhibit K-1 compares recent historical information collected by the National Fire Interagency Center on fire incidence by type. This figure shows the year-to-year variability in wildfire acres burned, but even though the acres with prescribed burning are increasing with time, there is no evidence that the wildfire acres burned is declining. In fact, recent years have seen historical highs in wildfire acres burned. This analysis focuses on 1998 to 2006, because the National Interagency Coordination Center says that national reporting of prescribed fires and acres began in 1998. Data for wildland fires and acres is available for the period 1960 to 2006.

Exhibit K-1. Wildland Fire Statistics



APPENDIX L

DOCUMENTATION OF VMT AND TEMPERATURE ASSUMPTIONS USED IN ONROAD MODELINGVEHICLE MILES TRAVELED (VMT)

APPENDIX L | DOCUMENTATION OF VMT AND TEMPERATURE ASSUMPTIONS USED IN ONROAD MODELINGVEHICLE MILES TRAVELED (VMT)

One of the key inputs to the estimation of onroad vehicle emissions is the activity used—vehicle miles traveled (VMT). Exhibit L-1 summarizes the 48-State (plus DC) VMT for each of the Section 812 analysis years. This table also shows the breakdown of VMT by vehicle type. This breakdown is very important to the overall calculation of emissions, since different vehicle types are subject to different emission standards and different motor vehicle emission control programs. As can be seen in this table, although total VMT increases throughout the analysis period, VMT from light-duty gasoline vehicles (LDGVs) peaks in 2000 and then decreases to 2020. In contrast, the light-duty gasoline truck 1 (LDGT1) category shows significant increases throughout the entire analysis period, so that by 2020, VMT for the LDGT1 category exceeds the VMT from the LDGV category. This pattern of replacing LDGV VMT with LDGT VMT generally leads to higher emissions than would occur if the distribution of VMT by vehicle type remained the same as in 1990. Another key factor is the continued growth of the heavy-duty diesel vehicle (HDDV) category throughout the analysis period. This vehicle category typically dominates PM and NOx emissions from onroad vehicles.

Exhibit L-1. Summary of 48-State VMT Used in Second Section 812 Prospective Analysis(VMT in millions of miles per year)

Vehicle Type	1990	2000	2010	2020
LDGV	1,330,701	1,592,790	1,473,483	1,443,782
LDGT1	332,388	615,388	1,067,946	1,476,433
LDGT2	152,480	205,549	355,931	491,748
HDGV	74,274	77,811	87,374	107,513
LDDV	22,579	4,886	1,763	1,760
LDDT	8,152	5,402	8,446	11,957
HDDV	134,851	201,399	261,173	327,356
MC	15,709	10,177	11,382	13,148
Total	***2,071,133***	***2,713,402***	***3,267,499***	***3,873,695***

TEMPERATURE

Another input affecting vehicle emissions (primarily VOC and CO, with some effects on NOx) is the temperature assumed. Average daily maximum and minimum temperatures are included as MOBILE6 inputs by month, with values provided at the State level. In 1990 and 2000, historical temperatures were used. For the 2010 and 2020 projection years, the temperature inputs reflect historical average 30-year temperatures. The temperature inputs used are shown in Exhibits L-2 through L-7. The temperature data used for a given State were generally selected from a metropolitan area that is either a major population center within the State or is geographically representative of a majority of the State. Due to its large geographic area and the differences in climate, California was broken into two separate temperature areas and each county in the State was assigned to one of these two areas based on climate and geography.

Exhibit L-2. 1990 Minimum Temperatures

State	State FIPS ID	January	February	March	April	May	June	July	August	September	October	November	December
AL	01	38.2	43.2	45.3	46.9	58.0	65.4	69.0	69.3	64.3	50.5	41.4	39.4
AK	02	8.8	0.0	20.0	30.7	42.3	49.7	51.1	50.0	44.1	25.7	2.9	7.7
AZ	04	43.9	45.1	55.4	63.9	68.5	79.8	82.6	79.5	76.1	65.6	53.7	42.5
AR	05	37.8	40.5	46.3	51.0	58.2	69.3	70.9	71.2	67.3	48.4	44.0	32.7
CA	06	49.3	48.9	53.4	58.3	58.8	64.1	68.0	66.0	66.9	62.5	54.6	47.1
CA	06	46.1	44.7	47.8	51.4	51.7	53.9	55.7	58.1	57.8	53.6	49.1	41.2
CO	08	24.2	21.3	27.7	37.1	42.4	56.2	57.5	56.6	52.8	37.1	30.2	11.9
CT	09	26.8	22.9	28.5	39.1	46.2	57.3	64.1	63.6	52.9	46.5	34.3	27.9
DE	10	33.7	33.3	37.2	43.8	53.4	61.4	68.6	67.3	58.6	52.9	39.3	34.5
DC	11	34.8	35.3	40.3	46.3	55.4	65.1	70.8	68.8	61.1	53.0	41.6	35.9
FL	12	54.6	58.9	58.0	61.1	68.8	72.2	73.6	73.9	72.4	68.3	59.3	55.1
GA	13	40.4	44.2	47.3	50.4	60.2	68.1	71.2	70.8	65.6	54.2	44.6	40.1
HI	15	68.9	64.3	66.0	68.5	70.7	73.1	73.0	74.7	74.9	73.6	70.2	67.3
ID	16	26.3	24.5	31.3	41.0	43.0	51.3	59.3	58.7	53.5	37.0	30.5	7.8
IL	17	27.4	27.7	36.0	40.6	50.6	63.6	65.9	64.5	57.7	41.4	37.9	21.4
IN	18	28.8	28.7	36.6	40.4	51.3	60.7	63.8	61.4	56.7	42.0	36.7	25.3
IA	19	22.5	20.4	32.8	39.1	47.7	62.2	65.3	64.9	57.2	40.3	32.8	14.4
KS	20	24.7	24.8	34.8	39.7	50.5	66.9	67.2	65.8	57.7	43.1	35.8	19.3
KY	21	34.3	34.7	41.7	43.9	55.3	64.6	67.8	66.7	62.0	47.1	40.7	31.3
LA	22	46.6	51.3	52.5	56.4	66.5	73.4	72.2	72.0	68.6	53.2	47.9	45.5
ME	23	22.3	15.0	25.0	36.1	42.7	53.1	60.4	60.2	51.0	42.6	32.0	25.2
MD	24	32.6	31.3	37.3	44.0	52.5	62.2	69.1	66.0	57.1	49.5	37.7	32.3
MA	25	29.5	25.0	31.4	40.1	47.5	58.3	65.2	66.3	56.9	49.9	40.1	32.6
MI	26	29.1	23.8	32.1	41.0	48.8	60.4	63.9	64.0	55.2	44.9	36.5	26.5
MN	27	17.1	13.8	26.6	35.6	45.9	59.4	61.7	61.2	53.9	36.5	27.9	7.9
MS	28	39.6	45.1	48.3	50.6	60.7	69.1	70.2	68.7	65.2	48.6	42.2	39.9
MO	29	29.3	30.1	39.1	43.3	52.5	65.4	67.4	65.9	61.2	43.3	41.0	25.0
MT	30	23.0	18.1	26.8	34.9	42.2	51.5	57.7	58.6	51.9	35.9	29.3	8.6
NE	31	23.2	18.8	31.9	36.3	48.1	63.7	65.9	64.9	53.6	41.2	28.7	15.6
NV	32	33.6	37.4	47.9	55.6	61.9	71.8	77.9	75.1	69.1	55.6	42.6	28.1
NH	33	19.3	11.9	22.3	34.2	40.8	53.1	57.7	58.3	47.9	39.9	28.8	20.8
NJ	34	33.1	30.2	35.5	43.9	52.3	63.6	69.7	68.1	59.8	53.4	40.8	34.3
NM	35	22.0	26.1	35.5	44.0	49.4	63.2	63.9	61.1	59.0	43.6	32.0	20.2
NY	36	35.5	31.7	36.0	45.1	52.0	64.2	70.1	69.5	62.2	56.4	43.9	36.4
NC	37	35.0	37.1	42.0	45.4	55.5	64.0	68.5	67.3	59.5	50.0	39.0	36.7
ND	38	13.0	7.3	22.9	28.8	40.7	52.8	56.2	57.1	46.7	28.0	17.8	0.0
OH	39	29.5	27.6	35.0	38.7	50.0	59.6	63.4	61.9	56.2	44.1	35.4	28.6
OK	40	34.3	35.0	43.0	49.1	58.3	71.3	70.3	70.8	66.3	48.7	43.5	26.8
OR	41	37.5	34.0	38.8	42.1	44.5	51.5	54.7	56.3	51.2	41.6	39.4	27.2
PA	42	29.5	28.1	34.4	42.2	50.0	60.1	65.4	63.5	55.4	47.5	36.0	29.5
RI	44	28.1	24.6	30.2	39.2	47.2	57.8	64.5	64.8	53.6	48.4	36.2	30.5
SC	45	38.5	43.1	47.2	49.0	59.2	67.3	71.7	70.9	63.3	53.7	40.2	40.6
SD	46	20.5	15.7	26.0	31.4	44.2	56.0	61.1	60.6	52.3	35.0	24.6	4.5
TN	47	35.5	38.9	43.5	45.7	55.7	66.4	69.1	67.7	63.2	47.2	42.4	33.3
TX	48	40.0	42.6	48.5	54.1	63.5	73.8	71.7	73.0	69.1	53.1	48.6	33.7
TX	48	46.6	48.8	53.5	59.7	69.7	74.3	72.2	73.1	69.4	56.0	51.9	42.6
UT	49	24.0	24.0	34.1	43.1	44.6	57.8	65.1	62.3	58.8	41.0	31.3	10.9

State	State FIPS ID	January	February	March	April	May	June	July	August	September	October	November	December
VT	50	18.6	10.0	20.5	33.8	39.6	53.1	56.3	56.2	47.0	40.0	28.3	17.6
VA	51	35.3	36.5	41.3	45.6	55.0	62.4	69.3	67.6	58.6	50.9	39.1	35.8
WA	53	37.7	34.0	39.0	44.3	46.3	51.2	56.8	56.5	53.9	44.2	41.4	30.4
WV	54	32.7	33.4	40.6	42.0	52.7	61.1	65.1	63.7	58.1	46.6	38.6	33.4
WI	55	23.5	20.5	31.6	40.0	45.2	57.3	62.9	63.6	57.8	42.0	36.0	19.6
WY	56	17.6	16.4	22.2	30.6	35.0	46.7	54.2	51.6	46.3	31.5	26.2	4.8

Exhibit L-3.1990 Maximum Temperatures

State	State FIPS ID	January	February	March	April	May	June	July	August	September	October	November	December
AL	01	59.7	65.7	68.6	74.4	79.8	90.2	90.5	95.3	90.7	77.3	70.0	59.9
AK	02	22.1	12.5	37.2	49.1	57.4	64.4	66.1	65.5	55.0	38.8	16.9	21.8
AZ	04	67.3	68.1	78.9	88.4	93.7	107.8	104.6	102.0	99.0	91.8	78.1	64.6
AR	05	58.4	62.0	64.5	72.9	77.9	91.9	95.4	93.2	87.7	74.5	68.5	53.5
CA	06	69.5	67.0	70.0	73.1	75.0	84.4	86.6	82.0	85.1	83.8	76.5	68.3
CA	06	59.4	59.2	61.9	67.0	66.3	70.8	70.0	72.4	74.1	74.8	66.8	57.0
CO	08	48.6	45.3	51.3	61.1	70.7	89.0	84.1	85.9	81.0	67.4	57.8	39.5
CT	09	42.5	43.1	51.9	59.3	67.2	80.6	84.7	83.0	75.0	68.3	54.6	45.5
DE	10	51.3	56.7	58.4	65.8	70.4	82.3	89.4	86.2	79.0	74.2	62.7	53.9
DC	11	52.3	55.1	60.1	67.3	73.1	84.8	87.9	84.2	78.1	72.5	62.4	53.1
FL	12	76.9	79.3	80.6	81.9	89.9	91.6	92.0	93.1	91.6	85.9	79.2	77.5
GA	13	59.2	64.5	68.0	73.4	80.5	89.0	89.9	90.3	85.8	74.6	68.3	58.1
HI	15	80.4	78.6	80.1	84.6	85.4	86.8	88.5	89.9	89.6	88.2	84.4	80.9
ID	16	42.0	43.7	57.3	68.4	68.3	82.4	93.0	89.2	86.2	65.0	51.8	28.4
IL	17	46.8	44.5	54.9	61.0	69.2	82.5	84.5	83.5	79.0	65.5	57.6	38.5
IN	18	45.8	46.5	55.8	62.4	68.9	81.8	84.0	83.5	77.1	65.7	58.3	43.9
IA	19	40.8	41.8	51.2	60.9	68.0	81.0	82.3	83.8	79.0	64.4	54.6	31.3
KS	20	49.8	47.5	56.1	64.0	70.1	87.4	88.2	87.2	85.4	70.9	62.3	39.9
KY	21	51.9	53.8	60.6	67.1	73.1	85.6	89.2	88.2	81.5	70.3	63.3	50.2
LA	22	67.2	69.9	73.9	79.7	86.6	94.3	92.2	93.8	90.5	79.8	75.1	67.1
ME	23	38.0	36.4	44.3	53.0	60.8	71.6	80.1	79.3	68.5	62.2	51.6	42.1
MD	24	51.3	53.2	57.8	65.5	72.1	84.4	87.6	83.1	77.5	71.9	61.5	52.1
MA	25	43.3	43.2	48.8	55.1	62.2	74.8	81.0	80.2	72.3	66.7	56.9	48.8
MI	26	39.9	37.4	46.4	59.0	66.3	78.0	81.4	79.8	73.3	61.7	52.6	39.8
MN	27	35.4	33.6	44.7	57.9	66.6	79.6	80.8	80.0	74.8	59.7	46.9	25.9
MS	28	62.3	67.3	71.6	76.7	82.8	93.4	92.7	95.9	91.5	78.7	73.7	63.7
MO	29	53.3	53.8	57.3	66.3	71.2	84.8	86.9	88.2	83.8	68.4	63.4	44.7
MT	30	39.4	39.8	49.3	57.3	65.0	78.6	86.5	86.6	81.0	61.4	51.8	29.8
NE	31	44.7	42.1	52.8	64.2	70.2	87.5	87.9	85.9	76.5	65.6	49.3	34.6
NV	32	56.8	60.1	73.1	82.0	87.0	99.9	103.7	100.5	94.8	82.8	67.6	52.3
NH	33	37.8	37.3	47.0	57.0	64.8	77.5	83.9	81.3	71.4	63.7	51.4	41.0
NJ	34	47.7	49.4	54.3	62.7	69.9	83.2	85.9	85.0	77.4	71.4	59.2	50.2
NM	35	47.2	50.9	61.6	70.6	77.8	94.7	89.7	86.4	82.7	73.0	57.9	43.9
NY	36	46.7	48.0	52.0	60.9	67.4	80.6	84.0	83.0	75.4	69.8	58.0	49.9
NC	37	55.6	59.8	63.3	70.7	76.4	86.3	90.1	87.3	81.5	72.3	65.8	55.8
ND	38	34.2	32.6	47.5	58.2	68.9	78.6	84.1	86.5	76.7	59.5	44.6	21.5
OH	39	45.8	47.3	55.6	62.6	68.1	80.9	83.7	83.0	76.6	66.0	57.0	45.8
OK	40	57.5	57.0	62.1	69.3	78.8	92.7	91.0	92.3	87.6	73.0	66.3	47.3
OR	41	48.6	48.9	58.7	64.7	65.8	72.6	86.0	82.8	78.4	62.5	54.4	41.0
PA	42	46.8	48.3	55.3	63.9	68.8	82.2	85.0	81.9	74.6	68.8	57.8	47.3
RI	44	44.5	43.9	50.0	56.9	64.8	77.5	81.4	82.1	73.8	68.7	56.7	48.5
SC	45	65.6	69.2	71.5	77.8	84.6	92.4	95.5	92.4	88.6	79.0	71.2	62.8
SD	46	41.2	38.6	48.8	60.3	67.8	82.7	86.6	87.9	82.3	64.0	51.6	27.4
TN	47	56.0	60.9	63.6	71.0	77.1	89.9	91.6	91.4	86.1	73.0	66.2	54.1
TX	48	63.5	65.1	66.8	73.9	83.2	94.2	93.3	96.2	90.9	79.6	71.0	54.3
TX	48	67.3	69.4	72.3	79.1	86.4	95.3	92.0	97.1	90.7	81.3	74.9	64.6
UT	49	42.8	41.6	55.9	66.7	71.0	86.2	92.6	90.0	85.1	66.9	51.5	31.0
VT	50	36.0	34.3	42.3	52.1	61.3	74.0	78.9	78.1	67.0	57.5	44.6	35.9
VA	51	57.2	59.4	62.8	70.2	76.5	87.6	90.5	84.9	80.4	75.3	66.0	56.7
WA	53	47.3	45.9	55.2	59.9	63.0	68.4	79.2	78.0	72.9	58.1	51.7	40.1
WV	54	51.9	56.9	62.7	68.1	73.1	83.4	86.4	84.4	79.2	69.8	62.8	53.8
WI	55	38.7	37.3	46.0	58.5	60.4	77.8	78.1	78.8	74.2	60.9	52.9	34.1
WY	56	40.5	39.4	48.5	57.9	66.0	82.4	85.4	85.4	80.1	61.0	47.6	26.8

Exhibit L-4.2000 Minimum Temperatures

State	State FIPS ID	City	January	February	March	April	May	June	July	August	September	October	November	December
AL	01	BIRMINGHAM	37.1	40.4	47.5	48.8	64.5	67.8	70.3	70.5	64.5	53.5	44.2	29.2
AK	02	ANCHORAGE	7.7	18.8	23.1	28.7	36.1	45.3	49.8	46.2	39.9	29.1	23.9	18.1
AZ	04	PHOENIX	44.6	48.0	51.3	60.6	70.1	78.3	83.1	81.9	77.9	62.0	45.8	44.3
AR	05	LITTLE ROCK	34.6	40.1	46.6	51.6	63.7	68.2	72.4	73.5	64.2	53.6	40.7	25.0
CA	06	LOS ANGELES	50.1	50.1	50.2	54.5	57.6	61.8	62.3	64.8	62.1	56.9	47.7	48.6
CA	06	SAN FRANCISCO	45.8	48.1	45.3	50.1	52.0	53.9	54.0	54.6	56.1	52.3	45.1	44.5
CO	08	COLORADO SPGS	20.2	23.4	25.4	33.4	42.8	50.1	56.6	56.2	46.4	37.0	18.4	13.5
CT	09	HARTFORD	14.5	22.3	30.6	36.5	47.1	55.7	57.7	58.3	51.3	38.5	32.1	16.8
DE	10	DOVER	25.6	30.0	39.1	44.4	56.3	64.8	65.3	66.0	58.6	48.5	37.6	23.8
DC	11	WASHINGTN DC NATL	27.4	31.9	40.2	45.8	57.2	65.4	66.1	66.9	59.5	49.3	37.1	24.4
FL	12	ORLANDO	47.9	48.8	55.6	56.7	64.6	69.3	72.1	71.7	72.3	61.9	53.0	48.1
GA	13	ATLANTA	34.1	37.6	45.0	46.6	61.2	66.4	69.4	69.4	62.3	52.1	41.6	27.4
HI	15	HONOLULU	65.7	66.2	68.2	69.1	70.7	72.6	74.1	74.3	73.4	73.4	71.3	66.4
ID	16	BOISE AIR	27.4	31.3	31.0	39.8	45.6	50.9	58.3	58.7	48.1	40.9	24.7	24.8
IL	17	SPRINGFIELD	19.3	29.7	34.4	40.2	54.0	60.2	63.4	64.7	53.3	46.3	29.2	8.8
IN	18	INDIANAPOLIS	18.9	28.6	34.6	40.2	53.6	60.8	61.9	63.0	54.0	46.1	32.0	11.4
IA	19	DES MOINES	16.4	26.7	33.1	38.3	51.1	57.7	64.1	65.9	54.8	46.7	25.0	2.8
KS	20	TOPEKA	21.5	28.9	34.5	42.0	55.7	60.7	68.3	70.9	56.7	49.1	26.8	11.2
KY	21	LOUISVILLE	25.1	34.2	39.6	43.8	57.5	64.5	67.2	67.1	57.7	48.4	36.2	18.1
LA	22	BATON ROUGE	45.0	48.4	54.0	54.9	67.4	70.6	72.9	73.3	67.2	54.6	46.9	36.5
ME	23	PORTLAND	11.6	17.1	28.5	34.0	42.4	52.8	56.4	57.5	48.5	37.8	32.5	15.4
MD	24	BALTIMORE	22.3	26.3	35.4	41.6	52.8	61.9	62.8	63.7	54.9	43.6	32.3	21.7
MA	25	BOSTON	17.6	25.3	33.4	38.6	47.3	57.9	61.8	62.1	54.3	45.2	37.5	22.0
MI	26	DETROIT	17.8	24.0	32.8	37.6	50.1	59.0	60.0	61.1	52.7	45.1	33.6	12.0
MN	27	MINNEAPOLIS	9.0	21.2	32.7	37.8	52.5	57.1	64.2	63.9	50.9	43.1	24.4	0.5
MS	28	JACKSON	36.9	39.2	47.1	50.2	63.3	67.4	70.1	70.4	64.9	50.5	41.9	28.4
MO	29	SPRINGFIELD	23.7	32.5	38.2	40.7	56.3	60.5	66.8	69.0	56.0	50.4	30.5	13.9
MT	30	BILLINGS	17.6	21.8	27.6	33.9	44.0	49.4	58.5	58.3	45.5	35.5	17.9	10.7
NE	31	LINCOLN	15.8	23.8	30.3	37.6	51.8	58.6	64.6	66.0	52.1	42.0	21.0	6.4
NV	32	LAS VEGAS	40.6	43.5	47.2	57.5	66.4	75.1	78.4	79.1	67.7	57.1	39.1	38.0
NH	33	CONCORD	9.6	14.9	25.6	33.7	42.8	52.8	54.3	55.2	44.6	34.6	27.8	12.8
NJ	34	NEWARK	22.9	29.4	37.0	41.8	53.7	61.5	64.7	64.7	57.1	47.1	37.2	22.7
NM	35	ALBUQUERQUE	27.8	32.0	33.5	44.0	53.7	62.1	65.4	65.7	58.3	45.8	28.4	25.6
NY	36	NEW YORK	23.9	30.1	37.5	42.4	53.8	62.3	66.1	67.3	60.7	50.8	40.3	25.4
NC	37	GREENSBORO	26.4	32.2	40.2	44.6	55.8	64.3	66.4	64.9	58.4	45.3	34.8	23.4
ND	38	BISMARCK	6.5	11.8	22.9	28.3	41.4	49.0	58.4	57.1	44.3	36.5	16.6	0.0
OH	39	COLUMBUS	18.5	27.7	34.3	39.8	53.2	61.1	61.0	61.0	54.8	46.0	32.7	15.1
OK	40	OKLAHOMA CITY	28.8	34.9	41.0	46.9	58.7	65.5	69.3	69.6	61.6	53.6	33.8	21.9
OR	41	EUGENE	33.3	36.7	33.3	38.8	43.9	47.0	47.7	47.7	45.9	39.8	30.5	34.0
PA	42	MIDDLETOWN	21.3	24.9	35.8	41.5	53.1	60.9	63.4	63.3	55.0	43.8	33.6	19.6
RI	44	PROVIDENCE	18.6	25.8	33.4	36.9	48.2	57.2	60.4	60.2	53.4	42.1	35.4	21.1
SC	45	COLUMBIA	32.0	34.8	43.1	47.8	60.9	67.5	70.1	69.8	62.8	47.0	39.5	26.3
SD	46	PIERRE	13.7	21.7	28.4	35.9	48.7	54.4	63.9	64.2	51.5	42.3	20.1	5.0
TN	47	NASHVILLE	29.0	35.2	40.1	45.9	59.8	66.2	68.5	68.6	59.9	49.1	38.0	22.0
TX	48	HOUSTON	45.4	48.8	54.4	54.7	68.6	71.1	72.0	71.5	66.4	59.4	48.8	36.6
TX	48	DALLAS-FT WORTH	40.4	45.8	50.1	53.0	65.7	71.5	75.6	77.8	68.2	60.4	40.7	30.4
UT	49	SALT LK CITY	25.8	29.6	30.3	41.1	49.1	56.4	65.3	65.2	51.4	41.1	23.3	22.0
VT	50	MONTPELIER	5.4	11.4	21.5	30.0	41.6	50.8	52.0	51.8	43.6	33.8	28.3	7.7
VA	51	RICHMOND	26.8	30.4	37.7	44.6	56.1	64.7	64.6	65.1	57.7	45.8	34.6	22.5
WA	53	SEATTLE-TACOMA	34.5	36.8	37.2	43.1	46.3	51.2	54.2	53.1	51.1	45.1	35.4	34.8
WV	54	CHARLESTON	22.0	31.8	35.5	40.7	53.7	61.1	60.5	61.7	54.6	43.0	33.3	19.7
WI	55	MILWAUKEE	16.7	24.1	31.7	35.3	48.8	55.8	60.1	62.5	53.7	45.6	30.2	9.6
WY	56	CASPER	15.8	23.5	23.5	28.0	38.3	42.9	50.8	52.9	40.5	31.9	11.5	10.5

Exhibit L-5.2000 Maximum Temperatures

State	State FIPS ID	City	January	February	March	April	May	June	July	August	September	October	November	December
AL	01	BIRMINGHAM	53.8	65.7	70.0	71.9	84.7	87.9	94.7	93.3	85.0	79.0	61.5	48.6
AK	02	ANCHORAGE	21.9	33.2	36.8	45.8	55.9	63.9	64.2	62.8	55.8	42.1	36.8	31.4
AZ	04	PHOENIX	71.3	74.5	76.1	90.6	100.0	104.4	107.3	104.4	102.9	84.4	68.1	70.8
AR	05	LITTLE ROCK	53.1	63.8	66.8	72.8	81.9	85.8	93.3	99.6	89.5	78.8	57.2	40.9
CA	06	LOS ANGELES	67.3	66.0	65.5	68.3	71.4	74.2	74.7	76.8	77.3	71.1	68.9	69.1
CA	06	SAN FRANCISCO	59.5	59.6	63.2	67.6	69.6	72.9	68.6	73.5	77.5	68.7	60.5	58.8
CO	08	COLORADO SPGS	48.3	54.6	53.4	67.5	76.6	81.0	87.3	87.6	78.3	64.3	44.7	44.4
CT	09	HARTFORD	36.3	41.6	56.7	60.7	72.8	80.5	81.4	81.5	75.1	65.5	50.9	36.6
DE	10	DOVER	41.1	48.1	58.2	60.9	73.1	81.7	80.5	80.0	74.5	67.9	53.7	39.3
DC	11	WASHINGTN DC NATL	45.4	54.0	64.5	66.7	78.8	84.4	83.8	83.8	78.0	72.6	57.5	40.7
FL	12	ORLANDO	75.0	76.3	83.4	84.2	91.3	92.9	93.8	92.5	91.0	83.7	79.2	72.2
GA	13	ATLANTA	53.0	64.3	70.4	72.3	84.0	89.5	93.0	90.3	79.9	76.6	62.0	48.1
HI	15	HONOLULU	79.0	81.3	82.6	81.5	85.4	87.9	87.6	88.5	87.6	87.2	83.4	82.5
ID	16	BOISE AIR	42.3	52.0	56.4	69.5	73.9	86.1	93.6	93.9	79.1	65.1	41.6	38.2
IL	17	SPRINGFIELD	37.9	49.3	61.1	67.1	79.4	81.1	83.4	86.3	82.8	71.9	49.6	27.7
IN	18	INDIANAPOLIS	38.3	49.4	59.5	64.1	76.7	81.9	83.6	83.8	77.1	71.1	51.2	29.9
IA	19	DES MOINES	37.9	47.3	59.0	67.9	78.7	81.2	83.6	86.6	83.3	69.8	45.8	21.6
KS	20	TOPEKA	46.3	56.8	61.0	72.2	82.2	85.1	91.2	99.5	89.2	74.0	50.4	31.5
KY	21	LOUISVILLE	43.8	56.7	64.8	69.8	80.9	85.9	86.4	87.7	79.8	74.5	55.3	35.7
LA	22	BATON ROUGE	66.0	72.6	76.6	77.8	88.4	90.8	93.1	95.4	88.9	81.0	67.0	57.4
ME	23	PORTLAND	33.2	37.2	48.0	54.2	64.1	75.6	78.4	78.6	72.5	61.9	50.1	35.1
MD	24	BALTIMORE	43.9	51.2	62.1	65.1	77.6	83.8	83.8	83.9	77.7	72.4	57.0	40.7
MA	25	BOSTON	38.7	44.3	53.1	56.9	67.7	77.9	78.7	78.0	74.5	64.3	51.1	38.9
MI	26	DETROIT	32.9	41.8	55.8	60.8	72.2	80.4	79.9	80.8	73.5	65.8	48.4	27.7
MN	27	MINNEAPOLIS	25.1	37.0	52.1	57.8	71.1	76.8	81.7	81.7	74.2	65.3	38.9	16.9
MS	28	JACKSON	61.4	70.2	74.8	75.2	86.3	90.5	96.5	99.2	89.8	81.1	65.1	52.1
MO	29	SPRINGFIELD	48.1	58.1	63.4	69.2	79.3	81.7	86.2	93.1	86.6	73.9	51.3	34.3
MT	30	BILLINGS	39.8	43.1	55.0	63.8	70.4	80.1	92.9	91.8	76.0	61.1	36.7	31.2
NE	31	LINCOLN	42.9	52.1	59.3	69.2	82.8	87.3	87.9	93.9	86.0	72.1	46.7	28.5
NV	32	LAS VEGAS	61.9	64.4	71.0	85.7	95.5	102.4	105.3	102.7	96.2	79.6	61.5	61.3
NH	33	CONCORD	33.2	38.3	52.8	59.1	69.8	79.1	80.8	80.5	74.6	64.7	50.0	34.6
NJ	34	NEWARK	42.0	47.0	59.0	62.4	74.6	83.4	83.7	82.2	77.3	68.8	53.4	40.0
NM	35	ALBUQUERQUE	54.4	60.0	63.5	75.7	87.1	91.0	93.4	91.6	87.2	68.3	50.4	50.1
NY	36	NEW YORK	41.6	46.5	57.0	59.9	73.1	82.4	82.5	81.8	77.4	67.8	53.7	39.9
NC	37	GREENSBORO	49.2	58.5	68.1	70.1	82.0	86.0	85.4	85.1	77.6	75.2	59.4	44.4
ND	38	BISMARCK	28.9	36.1	50.6	59.6	73.2	77.0	86.0	87.1	77.1	63.7	35.5	16.3
OH	39	COLUMBUS	37.1	47.1	58.4	63.7	76.9	83.3	83.4	82.0	76.5	70.6	50.9	32.4
OK	40	OKLAHOMA CITY	54.4	64.3	67.3	73.3	84.0	85.0	93.1	100.6	93.2	75.5	55.1	41.3
OR	41	EUGENE	47.2	51.3	56.0	65.1	67.2	79.0	82.2	83.6	78.4	66.3	50.7	48.7
PA	42	MIDDLETOWN	40.2	45.7	61.8	65.0	77.5	84.1	83.5	84.2	77.5	69.0	54.0	34.5
RI	44	PROVIDENCE	39.4	43.9	54.8	58.2	70.0	79.0	80.5	80.1	76.1	65.4	52.0	39.5
SC	45	COLUMBIA	55.9	65.4	73.8	75.6	90.4	92.5	93.6	91.8	83.9	78.8	66.6	51.0
SD	46	PIERRE	35.5	46.6	57.9	63.5	75.9	83.4	92.0	94.3	86.9	67.5	35.8	23.1
TN	47	NASHVILLE	49.7	61.0	67.7	70.3	81.4	87.7	92.0	91.8	84.0	78.1	61.0	41.0
TX	48	HOUSTON	70.8	74.8	79.4	80.8	87.7	90.7	97.9	98.1	93.8	82.1	69.7	59.7
TX	48	DALLAS-FT WORTH	64.9	72.7	74.3	77.5	88.3	90.0	99.0	102.4	95.1	79.9	60.0	50.3
UT	49	SALT LK CITY	44.5	50.3	54.5	69.6	76.7	87.9	96.6	93.0	79.2	65.1	40.9	40.7
VT	50	MONTPELIER	25.9	32.7	44.9	51.6	65.4	71.7	75.7	75.6	68.3	57.3	42.9	25.7
VA	51	RICHMOND	48.4	57.8	66.7	68.9	80.5	85.8	84.8	85.3	78.9	73.8	59.4	44.9
WA	53	SEATTLE-TACOMA	46.3	51.1	52.6	60.8	62.2	71.7	75.6	74.9	70.3	61.7	50.0	47.1
WV	54	CHARLESTON	43.7	55.0	65.2	68.8	80.2	84.8	81.8	81.3	77.6	72.9	56.5	39.0
WI	55	MILWAUKEE	32.7	41.0	52.8	54.9	68.7	77.2	77.4	80.2	72.3	65.1	44.4	25.8
WY	56	CASPER	41.6	46.8	53.7	64.8	72.6	83.6	93.9	93.1	76.6	63.4	33.0	33.7

Exhibit L-6.2010 and 2020 Minimum Temperatures

State	State FIPS ID	City	January	February	March	April	May	June	July	August	September	October	November	December
AL	01	Mobile	40.0	42.7	50.1	57.1	64.4	70.7	73.2	72.9	68.7	57.3	49.1	43.1
AK	02	Juneau	19.0	22.7	26.7	32.1	38.9	45.0	48.1	47.3	42.9	37.2	27.2	22.6
AZ	04	Phoenix	41.2	44.7	48.8	55.3	63.9	72.9	81.0	79.2	72.8	60.8	48.9	41.8
AR	05	Little Rock	29.1	33.2	42.2	50.7	59.0	67.4	71.5	69.8	63.5	50.9	41.5	33.1
CA	06	Los Angeles	47.8	49.3	50.5	52.8	56.3	59.5	62.8	64.2	63.2	59.2	52.8	47.9
CA	06	San Francisco	41.8	45.0	45.8	47.2	49.7	52.6	53.9	55.0	55.2	51.8	47.1	42.7
CO	08	Denver	16.1	20.2	25.8	34.5	43.6	52.4	58.6	56.9	47.6	36.4	25.4	17.4
CT	09	Hartford	15.8	18.6	28.1	37.5	47.6	56.9	62.2	60.4	51.8	40.7	32.8	21.3
DE	10	Wilmington	22.4	24.8	33.1	41.8	52.2	61.6	67.1	65.9	58.2	45.7	37.0	27.6
DC	11	Washington	26.8	29.1	37.7	46.4	56.6	66.5	71.4	70.0	62.5	50.3	41.1	31.7
FL	12	Miami	59.2	60.4	64.2	67.8	72.1	75.1	76.2	76.7	75.9	72.1	66.7	61.5
GA	13	Atlanta	31.5	34.5	42.5	50.2	58.7	66.2	69.5	69.0	63.5	51.9	42.8	35.0
HI	15	Honolulu	65.6	65.4	67.2	68.7	70.3	72.2	73.5	74.2	73.5	72.3	70.3	67.0
ID	16	Boise	21.6	27.5	31.9	36.7	43.9	52.1	57.7	56.8	48.2	39.0	31.1	22.5
IL	17	Chicago	12.9	17.2	28.5	38.6	47.7	57.5	62.6	61.6	53.9	42.2	31.6	19.1
IN	18	Indianapolis	17.2	20.9	31.9	41.5	51.7	61.0	65.2	62.8	55.6	43.5	34.1	23.2
IA	19	Des Moines	10.7	15.6	27.6	40.0	51.5	61.2	66.5	63.6	54.5	42.7	29.9	16.1
KS	20	Wichita	19.2	23.7	33.6	44.5	54.3	64.6	69.9	67.9	59.2	46.6	33.9	23.0
KY	21	Louisville	23.2	26.5	36.2	45.4	54.7	62.9	67.3	65.8	58.7	45.8	37.3	28.6
LA	22	New Orleans	41.8	44.4	51.6	58.4	65.2	70.8	73.1	72.8	69.5	58.7	51.0	44.8
ME	23	Portland	11.4	13.5	24.5	34.1	43.4	52.1	58.3	57.1	48.9	38.3	30.4	17.8
MD	24	Baltimore	23.4	25.9	34.1	42.5	52.6	61.8	66.8	65.7	58.4	45.9	37.1	28.2
MA	25	Boston	21.6	23.0	31.3	40.2	49.8	59.1	65.1	64.0	56.8	46.9	38.3	26.7
MI	26	Detroit	15.6	17.6	27.0	36.8	47.1	56.3	61.3	59.6	52.5	40.9	32.2	21.4
MN	27	Minneapolis-St. Paul	2.8	9.2	22.7	36.2	47.6	57.6	63.1	60.3	50.3	38.8	25.2	10.2
MS	28	Jackson	32.7	35.7	44.1	51.9	60.0	67.1	70.5	69.7	63.7	50.3	42.3	36.1
MO	29	Kansas City	16.7	21.8	32.6	43.8	53.9	63.1	68.2	65.7	56.9	45.7	33.6	21.9
MT	30	Great Falls	11.6	17.2	22.8	31.9	40.9	48.6	53.2	52.2	43.5	35.8	24.3	14.6
NE	31	Omaha	10.9	16.7	27.7	39.9	50.9	60.4	65.9	62.9	53.6	41.2	28.7	15.6
NV	32	Reno	20.7	24.2	29.2	33.3	40.1	46.9	51.3	49.6	41.3	32.9	26.7	19.9
NH	33	Concord	7.4	10.4	22.1	31.5	41.4	51.2	56.5	54.7	46.0	34.9	27.0	14.4
NJ	34	Atlantic City	21.4	23.5	31.3	39.3	49.6	58.7	64.8	63.5	55.5	43.7	35.8	26.3
NM	35	Albuquerque	21.7	26.4	32.2	39.6	48.6	58.3	64.4	62.6	55.2	43.0	31.2	23.1
NY	36	New York	25.3	26.9	34.8	43.8	53.7	63.0	68.4	67.3	60.1	49.7	41.1	30.7
NC	37	Raleigh	28.8	31.3	38.7	46.2	55.3	63.6	68.1	67.5	61.1	48.4	39.7	32.4
ND	38	Bismarck	0.0	5.1	17.8	31.0	42.2	51.6	56.4	53.9	43.1	32.5	17.8	3.3
OH	39	Columbus	18.5	21.2	31.2	40.0	50.1	58.0	62.7	60.8	54.8	42.9	34.3	24.6
OK	40	Oklahoma City	25.2	29.6	38.5	48.8	57.7	66.1	70.6	69.6	62.2	50.4	38.6	28.6
OR	41	Portland	11.4	13.5	24.5	34.1	43.4	52.1	58.3	57.1	48.9	38.3	30.4	17.8
PA	42	Philadelphia	22.8	24.8	33.2	42.1	52.7	61.8	67.2	66.3	58.7	46.4	37.6	28.1
RI	44	Providence	19.1	20.9	28.8	37.7	47.3	56.8	63.2	61.9	53.8	43.0	34.9	24.4
SC	45	Columbia	32.1	34.2	42.2	49.4	58.2	66.0	70.0	69.2	63.2	50.1	41.5	34.9
SD	46	Sioux Falls	3.3	9.7	22.6	34.8	45.9	56.1	62.3	59.4	48.7	36.0	22.6	8.6
TN	47	Nashville	26.5	29.9	39.1	47.5	56.6	64.7	68.9	67.7	61.1	48.3	39.6	30.9
TX	48	Dallas-Fort Worth	32.7	36.9	45.6	54.7	62.6	70.0	74.1	73.6	66.9	55.8	45.4	36.3
TX	48	Houston	39.7	42.6	50.0	58.1	64.4	70.6	72.4	72.0	67.9	57.6	49.6	42.2
UT	49	Salt Lake City	19.3	24.6	31.4	37.9	45.6	55.4	63.7	61.8	51.0	40.2	30.9	21.6
VT	50	Burlington	7.5	8.9	22.0	34.2	45.4	54.6	59.7	57.9	48.8	38.6	29.6	15.5
VA	51	Richmond	25.7	28.1	36.3	44.6	54.2	62.7	67.5	66.4	59.0	46.5	37.9	29.9
WA	53	Seattle-Tacoma	35.2	37.4	38.5	41.2	46.3	51.9	55.2	55.7	51.9	45.8	40.1	35.8
WV	54	Charleston	23.0	25.7	35.0	42.8	51.5	59.8	64.4	63.4	56.5	44.2	36.3	28.0
WI	55	Milwaukee	11.6	15.9	26.2	35.8	44.8	55.0	62.0	60.8	52.8	41.8	30.7	17.5
WY	56	Cheyenne	15.2	18.1	22.1	30.1	39.4	48.3	54.6	52.8	43.7	33.9	23.7	16.7

Exhibit L-7.2010 and 2020 Maximum Temperatures

State	State FIPS ID	City	January	February	March	April	May	June	July	August	September	October	November	December
AL	01	Mobile	59.7	63.6	70.9	78.5	84.6	90.0	91.3	90.5	86.9	79.5	70.3	62.9
AK	02	Juneau	29.4	34.1	38.7	47.2	55.1	60.9	63.9	62.7	55.9	47.1	36.7	31.6
AZ	04	Phoenix	65.9	70.7	75.5	84.5	93.6	103.5	105.9	103.7	98.3	88.1	74.9	66.2
AR	05	Little Rock	49.0	53.9	64.0	73.4	81.3	89.3	92.4	91.4	84.6	75.1	62.7	52.5
CA	06	Los Angeles	65.7	65.9	65.5	67.4	69.0	71.9	75.3	76.6	76.6	74.4	70.3	65.9
CA	06	San Francisco	55.6	59.4	60.8	63.9	66.5	70.3	71.6	72.3	73.6	70.1	62.4	56.1
CO	08	Denver	43.2	46.6	52.2	61.8	70.8	81.4	88.2	85.8	76.9	66.3	52.5	44.5
CT	09	Hartford	33.2	36.4	46.8	59.9	71.6	80.0	85.0	82.7	74.8	63.7	51.0	37.5
DE	10	Wilmington	38.7	41.9	52.1	62.6	72.9	81.4	85.6	84.1	77.7	66.6	55.5	43.9
DC	11	Washington	42.3	45.9	56.5	66.7	76.2	84.7	88.5	86.9	80.1	69.1	58.3	47.0
FL	12	Miami	75.2	76.5	79.1	82.4	85.3	87.6	89.0	89.0	87.8	84.5	80.4	76.7
GA	13	Atlanta	50.4	55.0	64.3	72.7	79.6	85.8	88.0	87.1	81.8	72.7	63.4	54.0
HI	15	Honolulu	80.1	80.5	81.6	82.8	84.7	86.5	87.5	88.7	88.5	86.9	84.1	81.2
ID	16	Boise	36.4	44.2	52.9	61.4	71.0	80.9	90.2	88.1	77.0	64.6	48.7	37.7
IL	17	Chicago	29.0	33.5	45.8	58.6	70.1	79.6	83.7	81.8	74.8	63.3	48.4	34.0
IN	18	Indianapolis	33.7	38.3	50.9	63.3	73.8	82.7	85.5	83.6	77.6	65.8	51.9	38.5
IA	19	Des Moines	28.1	33.7	46.9	61.8	73.0	82.2	86.7	84.2	75.6	64.3	48.0	32.6
KS	20	Wichita	39.8	45.9	57.2	68.3	76.9	86.8	92.8	90.7	81.4	70.6	55.3	43.0
KY	21	Louisville	40.3	44.8	56.3	67.3	76.0	83.5	87.0	85.7	80.3	69.2	56.8	45.1
LA	22	New Orleans	60.8	64.1	71.6	78.5	84.4	89.2	90.6	90.2	86.6	79.4	71.1	64.3
ME	23	Portland	30.3	33.1	41.4	52.3	63.2	72.7	78.8	77.4	69.3	58.7	47.0	35.1
MD	24	Baltimore	40.2	43.7	54.0	64.3	74.2	83.2	87.2	85.4	78.5	67.3	56.5	45.2
MA	25	Boston	35.7	37.5	45.8	55.9	66.6	76.3	81.8	79.8	72.8	62.7	52.2	40.4
MI	26	Detroit	30.3	33.3	44.4	57.7	69.6	78.9	83.3	81.3	73.9	61.5	48.1	35.2
MN	27	Minneapolis-St. Paul	20.7	26.6	39.2	56.5	69.4	78.8	84.0	80.7	70.7	58.8	41.0	25.5
MS	28	Jackson	55.6	60.1	69.3	77.4	84.0	90.6	92.4	92.0	88.0	79.1	69.2	59.5
MO	29	Kansas City	34.7	40.6	52.8	65.1	74.3	83.3	88.7	86.4	78.1	67.5	52.6	38.8
MT	30	Great Falls	30.6	37.5	43.7	55.3	65.2	74.6	83.3	81.6	69.6	59.3	43.5	33.1
NE	31	Omaha	31.3	37.1	49.4	63.8	74.0	83.7	87.9	85.2	76.5	65.6	49.3	34.6
NV	32	Reno	45.1	51.7	56.3	63.7	72.9	83.1	91.9	89.6	79.5	68.6	53.8	45.5
NH	33	Concord	29.8	33.0	42.8	56.3	68.9	77.3	82.4	79.8	71.6	60.7	47.1	34.2
NJ	34	Atlantic City	40.4	42.5	51.6	60.7	71.2	80.0	84.5	83.3	76.6	66.0	55.7	45.3
NM	35	Albuquerque	46.8	53.5	61.4	70.8	79.7	90.0	92.5	89.0	81.9	71.0	57.3	47.5
NY	36	New York	37.6	40.3	50.0	61.2	71.7	80.1	85.2	83.7	76.2	65.3	54.0	42.5
NC	37	Raleigh	48.9	52.6	62.1	71.7	78.6	85.0	88.0	86.8	81.1	71.6	62.6	52.7
ND	38	Bismarck	20.2	26.4	38.5	54.9	67.8	77.1	84.4	82.7	70.8	58.7	39.3	24.5
OH	39	Columbus	34.1	38.0	50.5	62.0	72.3	80.4	83.7	82.1	76.2	64.5	51.4	39.2
OK	40	Oklahoma City	46.7	52.1	62.0	71.9	79.1	87.3	93.4	92.5	83.8	73.6	60.4	49.9
OR	41	Portland	45.4	51.0	56.0	60.6	67.1	74.0	79.9	80.3	74.6	64.0	52.6	45.6
PA	42	Philadelphia	37.9	41.0	51.6	62.6	73.1	81.7	86.1	84.6	77.6	66.3	55.1	43.4
RI	44	Providence	36.6	38.3	46.1	57.0	67.3	76.9	82.1	80.7	74.3	64.1	53.0	41.2
SC	45	Columbia	55.3	59.3	68.2	76.5	83.5	88.8	91.6	90.1	85.1	76.3	67.8	58.8
SD	46	Sioux Falls	24.3	29.6	42.3	59.0	70.7	80.5	86.3	83.3	73.1	61.2	43.4	28.0
TN	47	Nashville	45.9	50.8	61.2	70.8	78.8	86.5	89.5	88.4	82.5	72.5	60.4	50.2
TX	48	Dallas-Fort Worth	54.1	58.9	67.8	76.3	82.9	91.9	96.5	96.2	87.8	78.5	66.8	57.5
TX	48	Houston	61.0	65.3	71.1	78.4	84.6	90.1	92.7	92.5	88.4	81.6	72.4	64.7
UT	49	Salt Lake City	36.4	43.6	52.2	61.3	71.9	82.8	92.2	89.4	79.2	66.1	50.8	37.8
VT	50	Burlington	25.1	27.5	39.3	53.6	67.2	75.8	81.2	77.9	69.0	57.0	44.0	30.4
VA	51	Richmond	45.7	49.2	59.5	70.0	77.8	85.1	88.4	87.1	80.9	70.7	61.3	50.2
WA	53	Seattle-Tacoma	45.0	49.5	52.7	57.2	63.9	69.9	75.2	75.2	69.3	59.7	50.5	45.1
WV	54	Charleston	41.2	45.3	56.7	66.8	75.5	83.1	85.7	84.4	78.8	68.2	57.3	46.0
WI	55	Milwaukee	26.1	30.1	40.4	52.9	64.3	74.9	79.9	77.8	70.6	58.7	44.7	31.2
WY	56	Cheyenne	37.7	40.5	44.9	54.7	64.6	74.4	82.2	80.0	71.1	60.0	46.8	38.8

APPENDIX M

FUGITIVE DUST TRANSPORT FACTORS

APPENDIX M | FUGITIVE DUST TRANSPORT FACTORS

For a number of years, it has been acknowledged that the ambient impact of fugitive dust sources is much less than emission inventories would suggest. Analysis of the chemical species collected by ambient air samplers suggests that the modeling process may overestimate PM-2.5 from fugitive dust sources by as much as an order of magnitude. This appendix documents assumptions that the Project Team will use in the subsequent air quality modeling steps to take account of processes that remove fugitive dust from the ambient air at or close to the source of emissions.

Fugitive dust sources of interest include unpaved and paved road dust, dust from highway, commercial and residential construction, and agricultural tilling. Of these, unpaved roads are the highest single emissions category, accounting for about one third of non-windblown fugitive dust emissions. This is followed in importance by dust from tilling, quarrying, and other earthmoving.

EPA does not include windblown dust emissions in its modeling inventories and the transport factors developed by EPA-OAQPS are not designed to be applied to windblown dust emissions.

For the emissions modeling performed for the first Prospective analysis, EPA-OAQPS provided an adjustment that was an *ad hoc* “divide the inventory by four” approach to reduce the discrepancy between modeling and ambient data. This adjustment factor was an interim approach that was developed as a placeholder until a more rigorous evaluation and analysis could be performed. EPA-OAQPS has now developed a method to estimate the transportable fraction of fugitive dust emissions for regional and urban scale air quality analysis (Pace, 2005) that is planned for use in the second Prospective analysis. The conceptual model behind the most recent EPA-OAQPS transport factor estimates is that the surrounding vegetative cover in an area (land cover type) has a strong influence on the fraction of PM-2.5 emissions that are transported beyond the local area of release. Five land cover types were identified and associated capture fractions were estimated for each land cover type based on field measurements. The five land cover types are: (1) forest, (2) urban, (3) scrub, sparsely wooded and grasses, (4) agricultural and (5) barren/water. The estimated ranges and recommended values for capture fractions are given in Exhibit M-1.

Exhibit M-1. Recommended Capture Fraction (%) for Five Land Cover Types

Land Cover Type	Average Height (m)	Recommended CF (%)	Estimated CF Range (%)	Comment
Forest	18 to 20	100	80 to 100	Forested areas will capture dust effectively.
Urban	5 to 50+	50	25 to 75	Structures are interspersed with open areas.
Scrub, Sparsely Wooded & Grasses	1 to 2	25	10 to 40	Portion of plume is below sparse vegetation.
Agricultural	1 to 2	25	10 to 40	Portion of plume is below crop (seasonally).
Barren / Water	0	0	0 to 10	Impediment-free surfaces are ineffective to capture dust.

In the emissions modeling process, each U.S. County has a single transport factor assigned that is multiplied by the PM-2.5 emissions for the applicable fugitive dust source categories to estimate transportable PM-2.5 emissions. The fraction of land area assigned to each land cover type in each U.S. County is obtained from the BELD dataset. The county average transportable fraction is estimated by combining the capture fractions in Table 1 with the corresponding fractional surface cover in each county and computing a weighted average capture fraction for each county. This information is then used to estimate the transport fraction for each county.

County-specific transport factors range from zero to 0.92. The average transport factor is 0.49 across all U.S. counties, which is less of a reduction in dust emissions than was realized in the old divide by four approach. The transportable fraction concept can be extended to finer spatial resolution using an emissions processor such as SMOKE. In fact, the WRAP has estimated the transportable fraction at a 2 km resolution in support of some of their analyses.

A preliminary estimate of the county-level transportable fractions was provided to the WRAP by OAQPS for use with their unpaved road dust emission inventory. Countess recently applied this concept to modeling in the San Joaquin Valley. He used the method developed by Pace and Cowherd to develop county-specific transportable fractions based on weighted average land use and ground cover information for the San Joaquin Valley counties. He found that use of those transportable fractions resulted in adjusted emission estimates that agree well with ambient measurements in these counties (Countess, 2003).

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APPENDIX N

ESTIMATES OF MERCURY EMISSIONS

APPENDIX N | ESTIMATES OF MERCURY EMISSIONS

In the First Prospective, EPA estimated the effect of CAAA provisions on airborne mercury emissions from five separate sources: medical waste incinerators, municipal waste combustors, electric utility plants, hazardous waste combustors, and chlor-alkali plants. Mercury regulation under the Clean Air Act is currently changing, as a recent ruling by the D.C. Circuit vacated the Clean Air Mercury Rule (CAMR). Accordingly, EPA will be reevaluating its approach to regulating mercury emissions for the purposes of this report, presents only a brief overview of projected mercury emissions and where possible an estimate of the effects of the CAAA on these emissions and has therefore decided to not devote extensive resources toward projecting mercury emissions in this report.

This appendix summarizes the mercury emissions projections from the First Prospective and presents new estimates of current and projected mercury emissions from selected sectors.

FIRST PROSPECTIVE PROJECTIONS

Exhibit N-1 summarizes the pre- and post-CAAA projections of mercury emissions from medical waste incinerators, municipal waste combustors, electric utility plants, hazardous waste combustors, and chlor-alkali plants for 1990, 2000 and 2010. As noted in Appendix A of the First Prospective Report, EPA estimated 1990 emissions for each of the five source categories and projected “without-CAAA” and “with-CAAA” emissions for both 2000 and 2010. In the Second Prospective emissions analysis, the 812 project team did not update the emissions estimates for municipal waste incineration, municipal waste combustion, hazardous waste combustion, and chlor-alkali plants, but new “without-CAAA” and “with-CAAA” emissions estimates for electric utility generation were generated for 2001, 2010, and 2020, as detailed in the following section. The updated EGU estimates, however, are based on projected implementation of the newly vacated CAMR.

Exhibit N-1. Mercury Emissions Projections for 2000 and 2010 from the First Prospective

Source Category	1990 Emissions (TPY)	2000 Emissions (TPY) Without-CAAA	2000 Emissions (TPY) With-CAAA	2000 Emissions (TPY) Diff.	2010 Emissions (TPY) Without-CAAA	2010 Emissions (TPY) With-CAAA	2010 Emissions (TPY) Diff.
Medical Waste Incineration	50	17.9	1.3	16.6	22.6	1.6	21
Municipal Waste Comb.	54	31.2	5.5	25.7	33.8	6	27.8
Electric Utility Generation	51.3	63	61.1	1.9	68.5	65.4	3.1
Hazardous Waste Comb.	6.6	6.6	6.6	0	6.6	3	3.6
Chlor-Alkali Plants	9.8	6	6	0	2	1.3	0.7
Total CAAA Benefits (Reductions)				**44.2**			**56.2**

IPM MODELING OF EGU EMISSIONS

As discussed in Chapter 4, the 812 project team used the Integrated Planning Model (IPM) to assess CAAA-related emissions impacts for NO_x, SO_2, and mercury, producing "without-CAAA" and "with-CAAA" emissions estimates for 2001, 2010, and 2020. The "with-CAAA" regulatory scenario that IPM applies to estimate 2010 and 2020 emissions assumes that the Clear Air Mercury Rule will be in effect, while the regulatory scenario for the 2001 estimate predates CAMR implementation. Exhibit N-2 presents the national mercury emissions estimates generated by the six IPM scenarios. By-state estimates of mercury emissions are presented in Exhibit N-9 at the end of this Appendix.

Exhibit N-2. IPM Mercury Emissions Estimates for EGUs in 2000, 2010, and 2020

	2000 Emissions (TPY)		2010 Emissions (TPY		2020 Emissions (TPY)	
Sector	**Without-CAAA**	**With-CAAA**	**Without-CAAA**	**With-CAAA**	**Without-CAAA**	**With-CAAA**
EGUs	53.5	42.1	58.3	34.7	59.6	24.4

The IPM-produced emissions estimates for 2000 and 2010, for both "without-" and "with-CAAA" scenarios, are lower than the estimates generated for the First Prospective Report, reflecting an enhanced understanding of actual EGU mercury emissions developed since the publication of the first prospective.

MERCURY EMISSIONS FROM OTHER SECTORS

1. GOLD MINING

The Project Team estimated mercury emissions from gold mines for 1990, 2000, 2010, and 2020. Because there are no current regulations under CAAA that affect mercury emissions from gold mines, these estimates are the same for both "without-CAAA" and "with-CAAA" scenarios.

To generate estimates of mercury emissions for the target years, the project team analyzed annual U.S. gold production data from USGS and temporally concurrent mercury emissions estimates from the Toxics Release Inventory (TRI). Years for which both mercury emissions and gold production are available are 1998 through 2004. Using this range of data the project team calculated production-based gold mining emissions factors for each year. These rate factors, presented in Exhibit N-3, represent the tons of mercury emissions released for every ton of gold produced.

Exhibit N-3. Gold Production and Mercury Emissions from 1998 to 2004

YEAR	1998	1999	2000	2001	2002	2003	2004
Gold produced (metric tons)	366	341	353	335	298	277	258
Total mercury emissions (metric tons)	6.2	5.5	5.6	5.5	3.9	2.2	2.2
Emissions factor (metric tons of mercury released / metric ton of gold produced)	0.0168	0.0162	0.0159	0.0163	0.0131	0.0081	0.0084
Approximate pre- and post-MACT Emissions factors				**0.016**			**0.008**
Sources: U.S. Environmental Protection Agency (EPA) (2007) Toxics Release Inventory. Website accessed 1/16/2007. Available at: http://www.epa.gov/enviro/html/tris/.; U.S. Geological Survey (USGS) (2007) Gold Statistic and Information. Website accessed 1/2							

An agreement between the four largest Nevada gold mining companies and EPA led to the application of maximum achievable control technology (MACT) beginning in 2001, resulting in a reported 75 percent reduction in mercury emissions by 2004 (EPA, 2006). Accordingly, the project team estimated two different gold mining emissions factors: one representing the pre-MACT period and one representing the post-MACT period. For purposes of this analysis, we assume that the pre-MACT emissions factor of 0.016 metric tons of mercury released per metric ton of gold produced describes the rate of mercury emissions for the target years 1990 and 2000, and the post-MACT emissions factor of 0.008 metric tons of mercury released per metric ton of gold produced describes the forecasted rate of mercury emissions for future target years 2010 and 2020.

Multiplying the pre- and post-MACT mercury emissions rate factors by the quantity of gold produced in each of the target years yields the estimate of airborne mercury emissions from gold production for that year. For 1990 and 2000, the project team uses gold production data from USGS. For 2010 and 2020, the project team assumes that future gold production in the U.S. will reflect historical patterns of gold production and therefore projects a range of annual gold production between 256 and 366 metric tons. The estimated annual gold production and mercury emissions for each of the target years are presented in Exhibit N-4. The table indicates a substantial reduction in mercury emissions in this category as a result of the negotiated MACT installations at Nevada facilities.

Exhibit N-4. Estimated Gold Production and Mercury Emissions for 1990, 2000, 2010, and 2020

	1990	2000	2010	2020
Estimated gold production (metric tons)	294	353	256 - 366 [a]	256 – 366 [a]
Estimated mercury emissions (metric tons)	4.7 [c]	5.6	2.0 - 2.9 [b]	2.0 - 2.9 [b]

Notes:
[a] These values are estimated based on the historical range of gold production in the U.S. since 1990.
[b] These values are estimated based on gold production estimates and the most recent emissions factor of 0.008 metric tons of mercury released per metric ton of gold produced.
c This value is estimated based on the actual quantity of gold produced in 1990 and the emissions factor of 0.016 metric tons of mercury released per metric ton of gold produced.
Data Sources: Gold production data are from (USGS, 2007.) and mercury emissions data are from (EPA, 2007.)

2. NON-EGU POINT SOURCES, AREA NONPOINTSOURCES, AND MOBILE SOURCES

Drawing from the 2006 updates to the 2002 National Emissions Inventory (NEI), the project team obtained mercury emissions data for point sources (both EGU and non-EGU), nonpoint area sources, and mobile sources, categorized by the first three digits of the Source Classification Code (SCC). These emissions are summarized in Exhibits N-5, N-6, and N-7. In Exhibits N-5 and N-6, the three-digit SCC codes are aggregated into broader categories, and total emissions of all mercury compounds are presented; the full speciation of mercury emissions from all point source and area nonpoint source categories is presented in Exhibits N-10 and N-11 at the end of this appendix. We made no attempts to project these estimates or estimate affect of CAAA for this analysis because of the state-of-flux of all mercury regulation at this point in time.

Exhibit N-5. 2002 NEI Mercury Emissions from Point Sources

Source Category	2002 NEI Mercury Emissions
Electric Generation	53.8
Industrial Processes, Primary Metal Production	11.5
No SCC record	10.2
Waste Disposal, Solid Waste-Industrial	7.7
Waste Disposal, Solid Waste-Govt.	6.9
Industrial Processes, Mineral Products	5.9
Industrial Processes, Chemical Manufacturing	5.8
External Combustion Boilers, Non-Electric Generation	2.8
Industrial Processes, Other Metal Production	2.5
Industrial Processes, Other	2.3
Waste Disposal, Other	0.7
Other	< 0.1
Total	***110.2***
Subtotal: Non-Electric Generation	***56.4***

Exhibit N-6. 2002 NEI Mercury Emissions from Nonpoint Area Sources

Source Category	2002 NEI Mercury Emissions (TPY)
Stationary Source Fuel Combustion	6.1
Miscellaneous Area Sources	1.9
Waste Disposal, Treatment, and Recovery	< 0.1
Total	***8.0***

Exhibit N-7. 2002 NEI Mercury Emissions from Mobile Sources

Source Category	2002 NEI Mercury Emissions (TPY)
Highway Vehicles – Gasoline	0.3
Highway Vehicles – Diesel	< 0.1
Total	***0.3***

SUMMARY OF RESULTS

A summary of mercury emissions estimates for the target years from different sectors and data sources is presented in Exhibit N-6.

N-8. Summary of Mercury Emissions

Sector	Data Source	1990 Emissions (TPY)	2000 Emissions (TPY)[a]		2010 Emissions (TPY)		2020 Emissions (TPY)	
			Without-CAAA	With-CAAA	Without-CAAA	With-CAAA	Without-CAAA	With-CAAA
EGUs	IPM	n/a	53.52	42.12	58.25	34.73	59.62	24.43
EGUs	First Prospective	51.3	63	61.1	68.5	65.4	n/a	n/a
EGUs	2002 NEI	n/a	n/a	53.8	n/a	n/a	n/a	n/a
Non-EGU Point Sources[b]	First Prospective	120.4	61.7	19.4	65	11.9	n/a	n/a
Non-EGU Point Sources	2002 NEI	n/a	n/a	56.4	n/a	n/a	n/a	n/a
Area Sources	2002 NEI	n/a	n/a	8.0	n/a	n/a	n/a	n/a
Mobile Sources	2002 NEI	n/a	n/a	0.3	n/a	n/a	n/a	n/a

[a] Data from the First Prospective represent estimates for 2000; data from IPM represent estimates for 2001; data from the 2002 NEI are for 2002.
[b] Combines emissions from medical waste incineration, municipal waste combustion, hazardous waste combustion, and chlor-alkali plants.

Exhibit N-9. IPM Projections of State-Level Mercury Emissions from EGUs for 2001, 2010, and 2020

State	2001 Emissions (TPY)		2010 Emissions (TPY)		2020 Emissions (TPY)	
	Without-CAAA	With-CAAA	Without-CAAA	With-CAAA	Without-CAAA	With-CAAA
Alabama	2.02	1.69	1.97	0.97	1.94	0.64
Arizona	0.54	0.52	0.74	0.86	0.88	0.78
Arkansas	0.62	0.56	0.85	0.87	0.87	0.51
California	0.12	0.12	0.13	0.09	0.13	0.09
Colorado	0.25	0.17	0.31	0.39	0.32	0.39
Connecticut	0.11	0.05	0.15	0.04	0.15	0.04
Delaware	0.06	0.10	0.07	0.12	0.14	0.14
District Of Columbia	0.00	0.00	0.00	0.00	0.01	0.00
Florida	1.22	0.87	1.22	0.48	1.24	0.45
Georgia	2.24	1.54	2.75	1.69	2.75	0.46
Idaho	0.00	0.00	0.00	0.00	0.00	0.00
Illinois	2.38	1.95	2.67	2.01	2.90	1.35
Indiana	2.77	2.20	3.38	1.44	3.53	0.84
Iowa	0.91	0.73	1.25	1.16	1.32	0.65
Kansas	0.98	0.53	1.14	1.03	1.26	0.60
Kentucky	2.05	1.47	2.15	0.90	2.25	0.50
Louisiana	0.46	0.47	0.49	0.48	0.52	0.34
Maine	0.02	0.04	0.02	0.02	0.02	0.01
Maryland	1.27	1.25	1.25	0.29	1.39	0.21
Massachusetts	0.46	0.22	0.51	0.23	0.52	0.15
Michigan	1.80	1.29	1.87	1.71	2.57	1.33
Minnesota	0.59	0.42	0.70	0.69	0.73	0.71
Mississippi	0.41	0.23	0.45	0.22	0.29	0.10
Missouri	2.34	1.51	2.65	2.32	2.60	1.09
Montana	0.33	0.27	0.34	0.32	0.34	0.32
Nebraska	0.53	0.39	0.55	0.55	0.55	0.54
Nevada	0.19	0.19	0.25	0.26	0.25	0.27
New Hampshire	0.22	0.27	0.22	0.05	0.22	0.05
New Jersey	0.28	0.26	0.39	0.19	0.36	0.16
New Mexico	0.47	0.41	0.48	0.62	0.48	0.35
New York	1.18	1.38	1.28	0.46	0.87	0.33
North Carolina	1.45	1.39	1.88	1.29	1.90	0.82
North Dakota	1.19	1.04	1.21	0.96	1.22	0.58
Ohio	4.93	3.59	4.35	1.45	4.34	1.28
Oklahoma	1.09	0.71	1.14	1.09	1.09	0.72
Oregon	0.08	0.05	0.08	0.08	0.08	0.08
Pennsylvania	6.13	4.66	6.39	1.53	6.23	1.17
Rhode Island	0.00	0.00	0.00	0.00	0.00	0.00
South Carolina	0.50	0.54	0.64	0.36	0.61	0.30
South Dakota	0.07	0.05	0.08	0.08	0.08	0.07
Tennessee	1.46	1.00	1.45	0.59	1.59	0.35
Texas	3.70	3.29	3.78	3.24	3.88	2.57
Utah	0.19	0.19	0.20	0.19	0.20	0.19
Vermont	0.00	0.00	0.00	0.00	0.00	0.00
Virginia	0.55	0.62	0.69	0.47	1.08	0.32
Washington	0.24	0.18	0.24	0.27	0.24	0.10
West Virginia	3.07	2.28	3.24	0.77	3.15	0.58
Wisconsin	1.38	0.97	1.40	1.25	1.55	1.02
Wyoming	0.68	0.48	1.26	0.63	1.00	0.87
Total	***53.52***	***42.12***	***58.25***	***34.73***	***59.62***	***24.43***

Exhibit N-10. 2002 NEI Point Source Mercury Emissions, Full Speciation

3 digit SCC	SCC Description, Part 1	SCC Description, Part II	2002 Point Source Mercury Emissions by Compound (tpy) Mercury & Compounds (Code: 199)	Elemental Gaseous Mercury (Code: 200)	Gaseous Divalent Mercury Code: 201)	Particulate Divalent Mercury (Code: 202)	Mercury (Code: 7439916)	Mercuric Chloride (Code: 7487947)	Mercury (Organic) (Code: 22967926)
101	External Combustion Boilers	Electric Generation	1.35323	28.64436	20.23304	1.39634	1.78897		
102		Industrial	0.52406				2.01243		0.00948
103		Commercial/Institutional	0.07761		0.00020		0.17658		0.00063
105		Space Heaters	0.01210				0.00024		
201	Internal Combustion Engines	Electric Generation	0.00444				0.42763		
202		Industrial	0.00018				0.03158		
203		Commercial/Institutional	0.00003				0.00126		
204		Engine Testing	0.00012				0.00016		
240	Solvent Utilization						0.00015		
280	Agricultural Field Burning - Point Sources						0.00125		
280	Internal Combustion Engines - Point Sources						0.00125		
280	"Miscellaneous Area Sources" - Point Sources						0.00125		
288	Internal Combustion Engines - Point Sources						0.00000		
301	Industrial Processes	Chemical Manufacturing	1.78702				4.01245		
302		Food and Agriculture	0.00001				0.03995		
303		Primary Metal Production	0.32337				11.17187		
304		Secondary Metal	0.30083	0.06000			2.06990		0.00014
305		Mineral Products	1.34381				4.55571	0.00012	0.00060
306		Petroleum Refining	0.00663				0.01414		
307		Pulp and Paper and Wood	0.54600				0.16403		
308		Rubber and Misc. Plastics					0.01520		
309		Fabricated Metals	0.00060				0.03600	0.02270	0.00001
310		Oil and Gas Production					0.30452		
312		Machinery, Misc.	0.00000				0.00000		
314		Transportation Equipment	0.00000				0.00065		
315	Industrial Processes	Photo Equipment	0.00121				0.02514	0.00150	
330		Textile Products	0.00004				0.00000		
385		Cooling Tower					0.09375		
390		In Process Fuel Use	0.00581				0.12676		
399		Misc. Manufacturing	0.74837				0.17956		0.00485
401	Petroleum and Solvent	Organic Solvent Evap.					0.00003		
402		Surface Coating Operations	0.00074				0.02759		

3 digit SCC	SCC Description, Part 1	SCC Description, Part II	2002 Point Source Mercury Emissions by Compound (tpy)						
			Mercury & Compounds	Elemental Gaseous Mercury	Gaseous Divalent Mercury	Particulate Divalent Mercury	Mercury	Mercuric Chloride	Mercury (Organic)
			(Code: 199)	(Code: 200)	Code: 201)	(Code: 202)	(Code: 7439916)	(Code: 7487947)	(Code: 22967926)
403	Evaporation	Petroleum Product Storage at Refineries	0.00001						
404		Petroleum Liquids Storage Non-Refinery	0.01089						
405		Printing/Publishing					0.00375		
407		Organic Chemical Storage	0.00005						
490		Organic Solvent Evap.	0.00000						
501	Waste Disposal	Solid Waste-Govt.	4.41470				2.46620		
502		Solid Waste-Comm/Institutional	0.21682				0.42795		
503		Solid Waste-Industrial	3.27848				4.40743		
504		Site Remediation	0.07051				0.00176		
Null SCC			9.05239				1.16134		
Point Sector Totals			**24.08004**	**28.70436**	**20.23324**	**1.39634**	**35.74844**	**0.02432**	**0.01571**

Exhibit N-11. 2002 NEI Area Non-Point Source Mercury Emissions, Full Speciation

3 digit SCC	SCC Description	2002 Non-Point Source Mercury Emissions by Compound (tpy)	
		Mercury & Compounds (Code: 199)	Mercury (Code: 7439916)
210	Stationary Source Fuel Combustion	0.00922	4.64344
219	Stationary Source Fuel Combustion		1.45738
260	Waste Disposal, Treatment, and Recovery		0.01292
262	Waste Disposal, Treatment, and Recovery	0.00003	0.01011
265	Waste Disposal, Treatment, and Recovery		0.00001
280	Miscellaneous Area Sources	0.01277	0.05620
281	Miscellaneous Area Sources	0.00124	0.23605
285	Miscellaneous Area Sources		0.88201
286	Miscellaneous Area Sources	0.01622	0.68087
Nonpoint Source Totals		**0.0348**	**7.97899**

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APPENDIX O

TRAJECTORY OF CAAA-RELATED EMISSION REDUCTIONS FOR THE 1990-2020 PERIOD

APPENDIX O | TRAJECTORY OF CAAA-RELATED EMISSION REDUCTIONS FOR THE 1990-2020 PERIOD

INTRODUCTION

This appendix presents the project team's assessment of the temporal trajectory of emission reductions associated with the Clean Air Act Amendments (CAAA) for the 1990-2020 period. As indicated in the main body of this document, the project team estimated emissions for seven pollutants in with-CAAA and without-CAAA scenarios for three target years: 2000, 2010, and 2020. Expanding upon these estimates, this appendix presents estimates of expected emission reductions for each year between 1990 and 2020. The purpose of generating this trajectory is twofold. First, the trajectory will inform the potential development of net present value estimates of the net benefits of the Amendments. Second, the emission reductions trajectory will provide useful insights with respect to the intra-decadal incidence of CAAA-related emission reductions. In the sections that follow, we summarize our approach for generating the emission reductions trajectory and present reductions estimates for each year during the 1990-2020 period.

SUMMARY OF METHODOLOGY

In this section, we describe our approach for developing the emission reductions trajectory for each pollutant. As described in greater detail below, the emission reductions trajectory is based primarily on the trajectory of CAAA-related costs.[14] As described in Appendix I of the Second Section 812 Prospective Direct Cost Analysis, the project team developed a trajectory of CAAA-related costs for each major source category that accounted for compliance dates of individual rules within each source category, as well as other factors. By basing the emission reductions trajectory on the cost trajectory, we effectively assume that changes in emission reductions are roughly proportional to changes in compliance costs. Because the cost trajectory is organized by source category, rather than by pollutant, we developed separate trajectories for all pollutants within each source category based on that source category's respective cost trajectory. We then combined the separate trajectories for each pollutant across source categories to produce a single emission reductions trajectory for each pollutant. As described below, we followed different processes to develop trajectories for emission reductions from EGUs, on-road vehicles and fuels, non-road engines and fuels, non-EGU point and nonpoint sources, and local controls.

[14] E.H. Pechan& Associates, Inc. and Industrial Economics, Direct Cost Estimates for the Clean Air Act Second Section 812 Prospective Analysis Draft Report, March 2009, Appendix I.

For each pollutant, we followed the following steps to generate an emission reductions trajectory between each set of target years (i.e., 1990 to 2000, 2000 to 2010, and 2010 to 2020):

- We created one emission reductions trajectory for each major source category, based on that source category's cost trajectory.
- We created an additional emission reductions trajectory for emission reductions from local controls; local controls begin to be applied in 2010 and continue through 2020.
- Combining these separate emission reductions trajectories, we produced a single trajectory for all reductions in emissions of each pollutant from 1990 to 2020.

ELECTRIC GENERATING UNITS

To develop the cost trajectory for electric generating units (EGUs), we employed two separate approaches, as summarized below:

EGU Emission Reductions - 1990 to 2000: To estimate emission reductions from the EGU sector for each year during the 1990-2000 period, we assume that the change in emission reductions for each pollutant in any given year relative to the previous target year (in this case, 1990) is based on the proportional relationship between (1) the difference between costs incurred that year and those achieved during the previous target year and (2) the difference between the costs for the following target year and the costs of the previous target year. This relationship can be illustrated by the following equation, using 1997 as an example year:

(O-1) $$\frac{EEx_{1997} - EEx_{1990}}{EEx_{2000} - EEx_{1990}} = \frac{CE_{1997} - CE_{1990}}{CE_{2000} - CE_{1990}}$$

Where EEx_{1997} = EGU sector emission reductions for pollutant x in 1997

EEx_{1990} = EGU sector emission reductions for pollutant x in 1990

EEx_{2000} = EGU sector emission reductions for pollutant x in 2000

CE_{1997} = EGU sector costs in 1997

CE_{1990} = EGU sector costs in 1990

CE_{2000} = EGU sector costs in 2000

If, for example, we estimate that the change in costs between 1990 and 1997 is approximately 59 percent of the change in costs between 1990 and 2000, then we would estimate the emission reductions for each pollutant in 1997 based on the following equation:

(O-2) $$EEx_{1997} = EEx_{1990} + 0.59(EEx_{2000} - EEx_{1990})$$

We followed the process described above to generate emission reductions trajectories for VOCs, CO, SO_2, PM_{10}, $PM_{2.5}$, and NH_3. For NO_x, however, we accounted for the fact that the Ozone Transport Commission Model Rule for NO_x went into effect in 1999 by setting emission reductions for NOx to 0 for all years prior to 1999. In addition, we assume that EGUs achieve no CAAA-related emission reductions until 1995, the year in which Phase 1 of the Title IV SO_2 allowance program went into effect.

EGU Emission Reductions – 2001 to 2020: For VOCs, CO, PM_{10}, $PM_{2.5}$, and NH_3 emission reductions from the EGU sector, we developed trajectories using the same projection method as we used for 1990-2000. For the trajectories of NO_x and SO_2 emission reductions from this sector, we made use of additional emission reductions estimates generated by IPM. As indicated in the main body of this report, we used IPM to estimate EGU NO_x and SO_2 emissions in both the with-CAAA and the without-CAAA scenarios for 2000, 2010, and 2020. IPM, however, also estimates NO_x and SO_2 emission reductions for 2007 and 2015, which we used in the trajectories for these two pollutants. Using the process described above, we then generated separate trajectories of NO_x and SO_2 emission reductions for 2001 through 2006, for 2008 through 2009, for 2011 through 2014, and for 2016 through 2019.

ON-ROAD VEHICLES AND FUELS

To generate emission reductions trajectories for the on-road sector, we first developed two parallel trajectories for each pollutant – one for fuel rules and inspection and maintenance (I&M) programs, and one for engine rules. We developed these trajectories by separating the emission reductions in each target year into two groups, and then employing two separate methods to develop trajectories between the target years. For each target year, we divided emission reductions between the two parallel trajectories according to the share of total costs incurred by each rule type. For example, in 2000, engine rules accounted for 35 percent of all CAAA-related costs in the on-road sector. Accordingly, we set reductions in VOC emissions due to engine rules to be 35 percent of total VOC reductions in 2000, or 219,352 tons. For each pollutant, we then developed emission reductions trajectories using the following two processes:

On-Road Engine Rules: For on-road engine rules, emission reductions are expected to be turnover-based, meaning that emission reductions will gradually increase each year as the total fleet of vehicles is replaced. Because of this cumulative effect, we assume that changes in emission reductions for these rules will be proportional to changes in cumulative costs over time. Using 1997 as an example, this relationship can be illustrated with the following equation:

(O-4) $$\frac{EORx_{1997} - EORx_{1990}}{EORx_{2000} - EORx_{1990}} = \frac{\sum_{i=1990}^{1997} COR_i}{\sum_{i=1990}^{2000} COR_i}$$

where $EORx_{1997}$ = On-road sector emission reductions for pollutant x in 1997

$EORx_{1990}$ = On-road sector emission reductions for pollutant x in 1990

$EORx_{2000}$ = On-road sector emission reductions for pollutant x in 2000

$\sum_{i=1990}^{1997} COR_i$ = The sum of on-road sector costs between 1990 and 1997

$\sum_{i=1990}^{2000} COR_i$ = The sum of on-road sector costs between 1990 and 2000

Using emission reduction values for each target year and cost values from the cost trajectory, we solved for $EORx_{1997}$ and all other years between target years.

On-Road Fuel Rules and I&M Programs: In contrast to the turnover-based emission impact of on-road engine rules, on-road fuel rules and I&M programs will affect emissions of the full fleet of on-road vehicles immediately upon the implementation of these programs. Accordingly, we assume that, from the compliance date onward, changes in the emission reductions related to fuel rules and I&M programs will be proportional to changes in costs over time. As indicated in Appendix I of the direct cost report, the cost trajectory developed by the project team accounts for the compliance dates of on-road rules.[15] Therefore, to develop a trajectory of the emissions reductions associated with on-road fuel rules and I&M programs, we relate the change in emission reductions between two target years (i.e., 1990, 2000, 2010, and 2020) to the change in costs over that same period. As with the trajectory for the EGU sector, we used the following equation, using 1997 as an example year:

(O-3) $$\frac{EORx_{1997} - EORx_{1990}}{EORx_{2000} - EORx_{1990}} = \frac{COR_{1997} - COR_{1990}}{COR_{2000} - COR_{1990}}$$

where $EORx_{1997}$ = On-road sector emission reductions for pollutant x in 1997

$EORx_{1990}$ = On-road sector emission reductions for pollutant x in 1990

$EORx_{2000}$ = On-road sector emission reductions for pollutant x in 2000

COR_{1997} = On-road sector costs in 1997

COR_{1990} = On-road sector costs in 1990

COR_{2000} = On-road sector costs in 2000

[15] E.H. Pechan& Associates, Inc. and Industrial Economics, Direct Cost Estimates for the Clean Air Act Second Section 812 Prospective Analysis Draft Report, March 2009, Appendix I.

As with the emission reductions trajectory for the EGU sector, we solved for $EORx_{1997}$, using the EGU cost trajectory and emission reduction estimates from the appropriate target years.

We combined the two parallel trajectories for reductions in emissions of each pollutant in the on-road sector into a single trajectory for each pollutant. As with the cost trajectory for non-road engines and fuels, the cost trajectory for on-road vehicles and fuels includes cost savings from fuel efficiency improvements. We did not modify the cost trajectory to remove these cost savings, however, because they composed a small percentage (between one and four percent) of total CAAA-related costs in this sector.

NON-ROAD ENGINES AND FUELS

Similar to the on-road sector, the non-road sector contains a combination of fuel rules and engine rules. Therefore, we approached the emission reductions trajectory for this sector in a similar manner to the trajectory for the on-road sector. Rather than developing two parallel trajectories for each pollutant, however, we used one method to develop the trajectory for SO_2 emission reductions and another method to develop the trajectory for reductions of all other pollutants.

For the SO_2 emission reduction trajectory, we assume that most emission reductions will be due to the Non-road Diesel Sulfur fuel rule, the initial phase of which went into effect in 2007. Because fuel rules are expected to affect emissions of the full engine fleet immediately upon their compliance date, we assume that, from the 2007 onward, changes in SO_2 emission reductions will be proportional to changes in costs over time. Accordingly, we developed the emission trajectories between target years using the same formula that we applied to develop emission reductions trajectories in the EGU sector and for fuel rules and I&M programs in the on-road sector (see equations O-1 and O-3).

For all other pollutants, we assume that emission reductions will be primarily due to engine rules. As with engine rules in the on-road sector, we assume that changes in emission reductions due to engine rules will be proportional to changes in cumulative costs over time. We therefore used the same approach to generate non-road emission reductions trajectories for VOCs, NO_x, CO, PM_{10}, $PM_{2.5}$, and NH_3 as represented by equation O-4 above.

For the non-road sector, we modified the cost trajectory in order to remove cost savings associated with fuel efficiency improvements. Fuel efficiency improvements save fuel, reducing net costs, but the total emission reductions track most closely to the gross expenditures for engine modifications or fuel reformulation. Because the fuel cost savings are expected to grow over time, the unmodified cost trajectory does not reflect the steady increase in emission reductions estimated in the Emissions Report from 1990 through 2000, 2010, and 2020. Removing cost savings from increased fuel efficiency creates a modified cost trajectory for the non-road sector that more closely corresponds to the overall trend of increasing reductions in all emissions in this sector.

NON-EGU POINT AND NONPOINT SOURCES

For non-EGU point sources and nonpoint sources, we developed emission reduction trajectories based on the respective cost trajectories for each of these source categories. For both of these sectors, we assume that the change in emission reductions for any given year relative to the previous target year (i.e., 1990, 2000, 2010, or 2020) is based on the proportional relationship between (1) the difference between costs incurred that year and those incurred during the previous target year and (2) the difference between the costs for the following target year and the costs for the previous target year. We therefore used the same formula for these sectors as we did for the EGU sector and for fuel rules and I&M programs in the on-road and non-road sectors (see equations O-1 and O-3).

LOCAL CONTROLS

As mentioned above, we created separate trajectories for emission reductions from local controls for each pollutant between 2010 and 2020. To develop trajectories for emission reductions achieved through local controls, we followed separate approaches for reductions achieved with identified controls and reductions achieved with unidentified controls. As described in Appendix I of the Section 812 cost report, the cost trajectory for local controls combines the cost of identified and unidentified controls into a single trajectory.[16] In order to generate separate emission reduction trajectories for identified and unidentified controls, we split that cost trajectory into two separate trajectories. To create a trajectory of costs for identified controls, we first determined what percent of the total costs of local controls were attributed to identified controls in the target years of 2010 and 2020. We then determined what percent of total local controls costs should be attributed to identified controls in each year from 2011 to 2012 by interpolating between the percent values in each target year. For example, in 2010, identified controls accounted for 36.8 percent of the $12.0 billion incurred by all local controls, while in 2020, identified controls accounted for 31.4 percent of the total cost of $16.6 billion. Accordingly, we interpolated between these two values to estimate that identified controls accounted for 36.3 percent of total costs in 2011, 35.7 percent of total costs in 2012, and so on. Multiplying these percent values to the cost trajectory for all local controls yielded a cost trajectory for identified controls; repeating the above steps for unidentified controls produced the second cost trajectory.

In a similar fashion, we further divided the cost trajectory for identified controls among the five major source categories and divided the cost trajectory for unidentified controls among area sources, on-road vehicles and fuels, and non-road engines and fuels, resulting in eight separate cost trajectories. We then used these cost trajectories to develop emission reduction trajectories for each pollutant in each source category where local controls were applied. Using the same formula that we applied to generate emission reduction trajectories for EGUs, on-road fuel rules and I&M programs, non-road fuel rules, non-EGU point sources, and nonpoint sources (see equations O-1 and O-3), we

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[16] E.H. Pechan& Associates, Inc. and Industrial Economics, Direct Cost Estimates for the Clean Air Act Second Section 812 Prospective Analysis Draft Report, March 2009, Appendix I.

generated trajectories for emission reductions from identified controls for VOCs, NO_x, SO_2, PM_{10}, and $PM_{2.5}$, and for emission reductions from unidentified controls for VOCs and NO_x. Combining the separate emission reduction trajectories for each pollutant provided emission reduction trajectories for all reductions due to local controls.

RESULTS

Exhibit O-1 presents the estimated emission reductions trajectory for 1990 through 2020 based on the methods described in the previous section. Exhibits O-2a and O-2b present trajectories for VOCs, NO_x, SO_2, PM_{10}, and $PM_{2.5}$ in a graphic format.

Exhibit O-1. Trajectory of CAAA-Related Emission Reductions: 1990 through 2020 (tons of pollutant reduced)

Year	VOC	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	NH_3
1990	0	0	0	0	0	0	0
1991	473,008	169,546	589,108	194,561	444,873	22,516	13,283
1992	534,481	177,852	712,594	170,862	504,242	28,689	13,409
1993	485,519	192,613	939,972	215,943	438,652	22,172	13,495
1994	904,307	369,861	2,694,638	318,580	776,642	47,177	20,753
1995	1,287,592	537,287	4,772,183	5,336,691	1,081,757	89,195	25,182
1996	3,157,395	1,230,412	8,372,418	5,592,522	2,750,940	179,474	73,038
1997	4,237,364	1,523,427	10,111,097	5,592,195	3,660,488	240,441	93,712
1998	5,062,138	1,814,092	12,673,471	5,829,300	4,262,989	281,381	109,249
1999	6,044,901	3,674,770	16,213,423	7,626,372	4,963,936	321,572	133,723
2000	6,679,121	5,851,287	19,402,611	9,809,985	5,274,852	332,960	152,697
2001	7,239,311	6,702,190	22,810,295	10,357,877	5,339,414	370,028	162,810
2002	7,673,337	7,234,001	23,463,212	11,027,402	5,476,021	402,389	170,708
2003	7,911,791	7,683,582	24,534,690	11,528,546	5,528,685	428,024	173,083
2004	8,280,583	8,326,227	26,829,873	12,047,135	5,584,749	456,907	175,620
2005	8,609,772	8,888,391	28,565,582	12,556,241	5,640,365	485,705	178,009
2006	9,577,199	10,458,238	36,842,654	13,159,722	5,710,088	527,883	180,849
2007	10,109,248	11,239,884	39,778,724	13,731,839	5,777,189	564,567	180,907
2008	10,533,863	12,009,977	41,451,743	14,581,036	5,836,179	593,238	180,882
2009	10,948,205	12,740,880	42,846,856	15,439,097	5,895,720	622,384	180,840
2010	12,369,732	14,627,198	47,446,553	16,484,151	5,992,011	682,447	180,893
2011	12,891,893	15,394,669	50,088,170	16,897,215	6,168,722	726,056	182,850
2012	13,251,009	15,891,667	51,513,964	17,304,086	6,335,239	760,225	184,772
2013	13,673,832	16,510,079	53,589,295	17,713,823	6,503,953	796,467	186,715
2014	14,187,212	17,254,929	55,809,764	18,150,448	6,675,669	836,909	188,663
2015	14,601,167	17,855,000	57,806,424	18,551,498	6,844,180	872,887	190,603
2016	15,083,284	18,470,021	60,542,370	18,745,877	7,014,829	910,906	192,566
2017	15,824,445	19,441,279	63,347,456	19,061,318	7,192,572	960,128	194,533
2018	16,307,813	20,064,489	66,143,988	19,256,757	7,362,861	997,708	196,498
2019	16,763,098	20,631,575	68,636,825	19,448,039	7,532,297	1,034,492	198,453
2020	17,237,613	21,236,046	71,332,461	19,639,637	7,702,293	1,071,814	200,415

Exhibit O-2a. Trajectory of CAAA-Related Reductions in VOC, NO_x, and SO_2 emissions: 1990 through 2020 (tons of pollutant reduced)

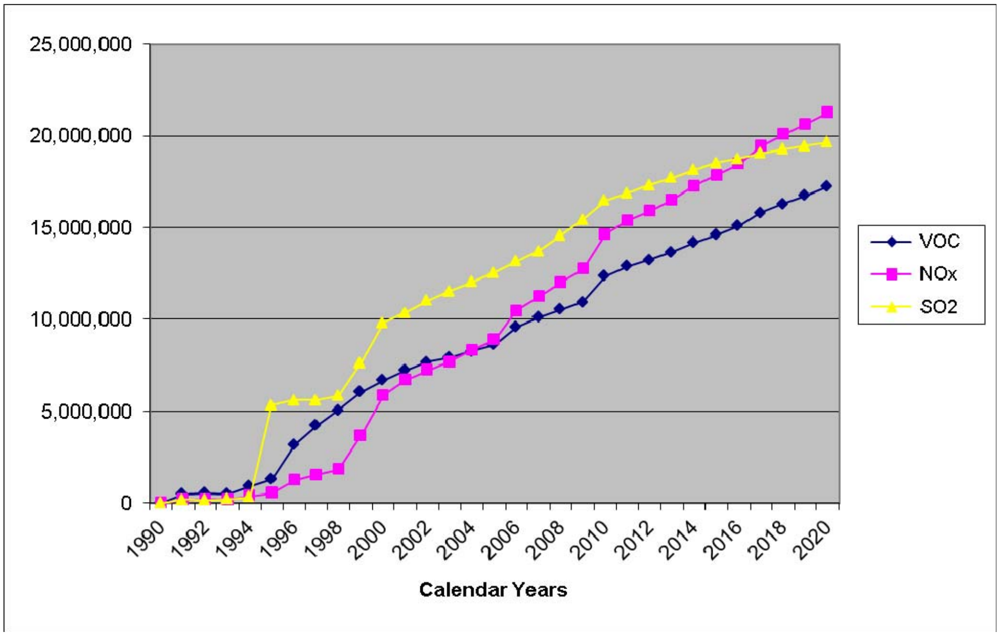

Exhibit O-2b. Trajectory of CAAA-Related Reductions in PM_{10} and $PM_{2.5}$ emissions: 1990 through 2020 (tons of pollutant reduced)