DIRECT COST ESTIMATES FOR THE CLEAN AIR ACT SECOND SECTION 812 PROSPECTIVE ANALYSIS

DRAFT REPORT

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[NOTE: Appendices omitted from this draft]

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ACRONYMS AND ABBREVIATIONS

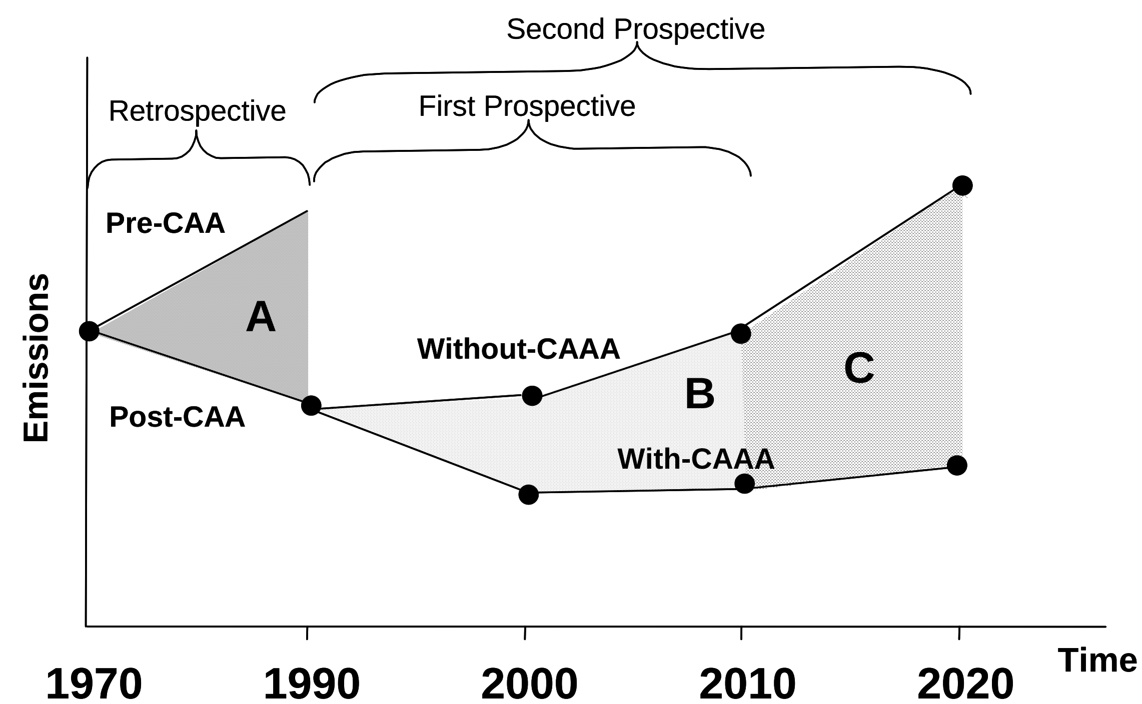
AIM	architectural and industrial maintenance
ASM	Acceleration Simulation Mode
ATP	anti-tampering
ATV	all-terrain vehicles
BAAQMD	Bay Area Air Quality Management District
BART	best available retrofit technology
BID	background information document
C-I	compression ignition
CAA	Clean Air Act
CAAA	Clean Air Act Amendments of 1990
CARB	California Air Resources Board
CAVR	Clean Air Visibility Rule
CCV	closed crankcase ventilation
CDPF	catalyzed diesel particulate filter
CFFP	Clean Fuel Fleet Program
CFFV	clean fuel fleet vehicle
CFV	clean fuel vehicle
CMV	commercial marine vessel
CNG	compressed natural gas
CO	carbon monoxide
DOT	Department of Transportation
EGR	exhaust gas recirculation
EGU	electricity generating unit
EPA	U.S. Environmental Protection Agency
FCCU	fluid catalytic cracking unit
FCU	fluid coking units
g/bhp-hr	grams per brake horsepower hour
g/mi	grams per mile
GDP	gross domestic product
GVW	gross vehicle weight
HC	hydrocarbon
HDDV	heavy-duty diesel vehicle
HDGV	heavy-duty gasoline vehicle
HDV	heavy-duty vehicle
HRVOC	highly reactive volatile organic compound
I/M	inspection and maintenance
IPM	Integrated Planning Model
km	kilometer
kW	kilowatt
L&M	locomotive and marine
LDGT	light-duty gasoline truck
LDGV	light-duty gasoline vehicle
LDT	light-duty truck
LDV	light-duty vehicle
LPG	liquefied petroleum gas
LVW	loaded vehicle weight
MDPV	medium-duty passenger vehicle
mmBtu	million British thermal units
MPO	Metropolitan Planning Organization

NAAQS	National Ambient Air Quality Standards
NCP	Non-Conformance Penalty
NEI	National Emissions Inventory
NMHC	nonmethane hydrocarbons
NMOG	nonmethane organic gas
NO_x	oxides of nitrogen
NPV	net present value
NRLM	nonroad, locomotive, marine
O&M	operation and maintenance
OAR	Office of Air and Radiation
OBD	onboard diagnostic
OTC	Ozone Transport Commission
PADD	Petroleum Administration for Defense District
PM_{10}	Particulate matter less than or equal to 10 micrometers
$PM_{2.5}$	Particulate matter less than or equal to 2.5 micrometers
ppm	parts per million
psi	pounds per square inch
RACT	reasonably available control technology
RACM	reasonably available control measure
RFP	reasonable further progress
RIA	regulatory impact analyses
ROI	return on investment
RPE	retail price equivalent
RVP	Reid vapor pressure
S-I	spark ignition
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
SCC	source classification code
SCR	selective catalytic reduction
SIP	State implementation plan
SNCR	selective noncatalytic reduction
SO_2	sulfur dioxide
TAC	total annualized costs
TCEQ	Texas Commission on Environmental Quality
TIP	Transportation Improvement Program
TLEV	transitional low emission vehicle
tpy	tons per year
ULEV	ultra-low emission vehicle
VMT	vehicle miles traveled
VOCs	volatile organic compounds
VTEC	Variable Valve Timing and Lift Electronic Control
ZEV	zero-emission vehicle

CHAPTER 1 - INTRODUCTION

Section 812 of the Clean Air Act Amendments of 1990 (CAAA) requires 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 required was a retrospective analysis, addressing the original CAA and covering the period 1970 to 1990. The retrospective was completed in 1997. Section 812 also requires 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. Exhibit 1-1 below outlines the relationship among the Section 812 Retrospective, the First Prospective, and the Second Prospective.

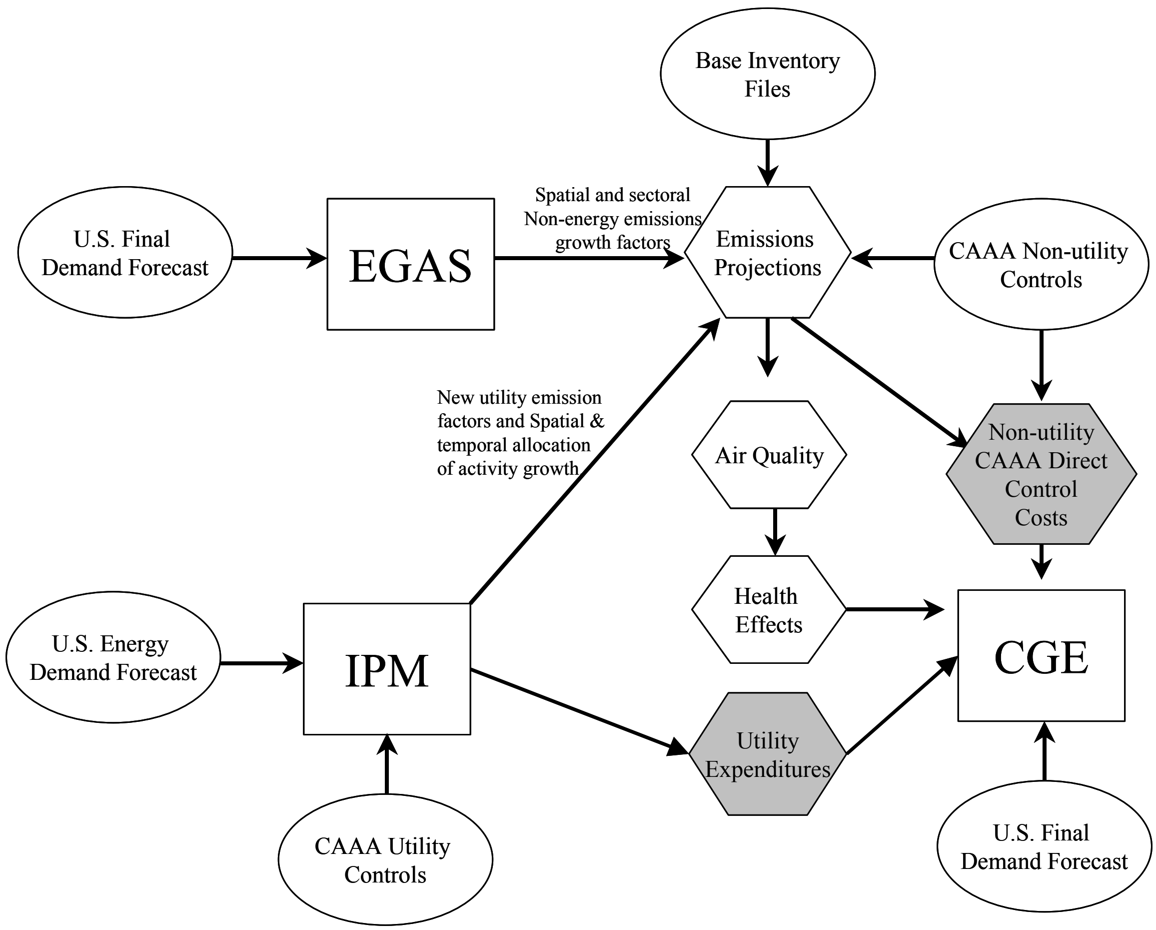
Exhibit 1-1. 812 Scenarios: Conceptual Schematic



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). The Council provided comments on the plan, which have been incorporated into the revised technical analysis planning.

Exhibit 1-2 provides a summary of the key technical steps in the completion of the second prospective. The first step in the second prospective analysis was the development of base and projection year emission estimates, which will be subsequently be used to generate benefit estimates of CAAA programs. The emission estimates have been published in draft form (Pechan and IEc, 2006). They were reviewed by the Council's Air Quality Modeling Subcommittee in August 2006 and are in the process of refinement to reflect comments received.

Exhibit 1-2. May 2003 Analytical Plan - Schematic Flow Chart



This report provides the combination of Utility (EGU) and Non-Utility direct costs (the two shaded boxes)

This report provides the corresponding direct cost analysis represented by the shaded boxes in Exhibit 1-2 above.[1] It addresses both the utility expenditures that result from the Integrated Planning Model (IPM), and the non-utility CAAA control costs. The estimates presented here, once reviewed and accepted by the Council, will subsequently be used both as a key stand-alone output of the Second Prospective and as inputs in the computable general equilibrium modeling. The CGE model will also incorporate certain benefits-side expenditure effects, such as differences in population, avoided health costs, and, to the extent possible, labor productivity benefits of the CAAA.

[1] In almost all cases, except where noted below, the cost estimates presented in this draft reflect the same economic growth assumptions, intermediate data inputs, rule effective dates, rule-effectiveness assumptions, and other key assumptions and inputs used in the June 2006 draft emissions analysis.

Note also that the cost estimates presented in this report represent direct expenditures associated with CAAA-related compliance. As such, they do not reflect how the Amendments may interact with existing distortions in the economy. For example, a body of research suggests that environmental regulation such as the CAAA may exacerbate the economic distortions associated with the income tax.[2] Industries that incur costs to meet the requirements of the Amendments may pass such costs onto consumers in the form of higher prices. This increase in the price level results in a reduction in the real wage (i.e., the purchasing power of labor income), which may induce workers to contribute less to the labor force. The magnitude of the resulting welfare loss, known as the tax interaction effect, depends significantly on the marginal income tax rate; the higher the marginal tax rate, the more significant the loss.[3] Because of this effect, the social costs and, as some literature suggests, the benefits of the Amendments may exceed the direct CAAA-related costs incurred by regulated industries and the directly estimated mandatory benefits. The tax interaction effect is not reflected in the expenditure-based cost estimates presented in this report. The project team plans to address the tax interaction effect and the broader social costs and benefits of the CAAA in the CGE analysis referred to above, to be conducted at a later date.

The remainder of this introductory chapter summarizes the overall approach used to estimate direct costs, and provides a description of the model sets, and summarizes direct costs by CAAA Title.

Summary Of Direct Cost Approach

The scope of this analysis is to estimate the incremental direct costs for all criteria and hazardous air pollutant regulations issued under CAAA programs. The increment of interest corresponds to the difference in costs incurred under two scenarios, depicted in schematic form in Exhibit 1-1 above:

1. A historical, "with-CAAA" scenario control case that reflects expected or likely future measures implemented since 1990 to comply with rules promulgated through September 2005[4]; 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 growth in population and economic activity and, therefore, in emissions attributable to economic and population growth.

As a result of our adopting an incremental approach to cost estimation, a single cost estimate is presented for each relevant rule, rather than total costs for the two primary scenarios.

[2] For a review of tax interaction effects see, Lawrence H. Goulder, Ian W.H. Parry, Roberton C. Williams, and Dallas Burtraw, " The cost-effectiveness of alternative instruments for environmental protection in a second-best setting," *Journal of Public Economics*, Vol. 72 (1999), 329-360; Roberton C. Williams III, " Revisiting the cost of protectionism: The role of tax distortions in the labor market," *Journal of International Economics*, Vol. 47, (1999), 429-447; and Roberton C. Williams III, Environmental Tax Interactions when Pollution Affects Health or Productivity," *Journal of Environmental Economics and Management*, Vol. 44, (2002), 261-270.

[3] More specifically, this loss is estimated as the difference between the pre-tax wage rate and the wage received by workers multiplied by the reduction in labor supply.

[4] 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 omissions (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.

While the emissions analysis addressed only criteria pollutant emissions, the direct cost analysis addressed CAAA provisions issued to control emissions of criteria pollutants and hazardous air pollutants (HAPs).

We estimate direct costs in projection years 2000, 2010, and 2020 using control assumptions consistent with those of the emissions and benefits analysis. The costs summarized in this analysis reflect the most recent cost data available for CAAA-based regulations issued to date. This report presents the results of EPA's analysis of the projected costs associated with implementation of the CAAA programs to control air emissions from the following sectors: non-EGU point sources, EGUs, nonroad engines/vehicles, onroad vehicles, and nonpoint (area) sources.

The control measures for which costs are estimated in this analysis are consistent with the control assumptions modeled in the second section 812 emission projections analysis. For each source category, unit cost information was developed in a form that can be applied to the point, nonpoint, nonroad, and onroad vehicle emission inventories in 2000, 2010, and 2020. This report describes the cost information used in AirControlNET, the IPM, and other control cost tools to generate estimates of CAAA costs in 2000 and 2010 by control measure and CAAA Title. In general, cost information was obtained from regulatory impact analyses (RIAs), background information documents (BIDs), regulatory support documents, and *Federal Register* notices.

The summary direct cost measures presented at the end of this chapter and the end of each of the emission sector chapters are expressed in 1999 dollars. Within each of the sector chapters, however, and in order to adequately document our source data, we often present estimates in the year's dollars of the original source. Conversions to 1999 dollars use the GDP implicit price deflator series.[5] For the purposes of annualizing capital investments, a discount rate of 5 percent is used wherever possible.[6]

Learning Curve Impacts

A significant body of literature suggests that the per unit cost of producing or using a given technology declines as experience with that technology increases over time.[7] In developing the cost estimates presented in this report, the Project Team accounted for these learning curve impacts as they relate to the costs of the Amendments. Although learning curves are likely to influence the costs associated with most CAAA provisions, the Project Team limited its learning curve cost adjustments to those technologies and source categories for which the learning curve literature supports such an

[5] The series we relied on is the GDP implicit price deflator, found in Table B-3 on page 284 of the *Economic Report of the President*, Transmitted to Congress February 2006, United States Government Printing Office: Washington, DC. Note that some components of the analysis that rely on the AirControlNET tool appear to have made use of a slightly different price index. At the time of this draft, we have not yet updated the AirControlNET cost adjustment time series, but we believe the differences introduced by this inconsistency in approach are very slight.

[6] In a few cases, the source for cost estimates either does not include a statement of the discount rate assumption or does not include enough information to standardize the cost to a 5 percent discount rate. These exceptions are noted in the text.

[7] These studies include John M. Dutton and Annie Thomas, "Treating Progress Functions as a Managerial Opportunity," *Academy of Management Review*, 1984, Vol. 9, No. 2, 235-247; Dennis Epple, Linda Argote, and Rukmini Devadas, "Organizational Learning Curves: A Method for Investigating Intra-plant Transfer of Knowledge Acquired Through Learning by Doing," *Organizational Science*, Vol. 2, No. 1, February 1991; International Energy Agency, *Experience Curves for Energy Technology Policy*, 2000; and Paul L. Joskow and Nancy L. Rose, "The Effects of Technological Change, Experience, and Environmental Regulation on the Construction Cost of Coal-Burning Generating Units," *RAND Journal of Economics*, Vol. 16, Issue 1, 1-27.

adjustment. More specifically, the Project Team incorporated learning curve impacts into the cost estimates for motor vehicle engine controls and flue gas desulfurization (FGD), selective catalytic reduction (SCR), and selective noncatalytic reduction (SNCR) retrofits installed by electric generating units. Our learning curve adjustments for motor vehicle engine controls are based on analyses of learning associated with the production of automobiles and trucks, while the adjustments for FGD, SCR, and SNCR are based on studies specific to each of these technologies. Exhibit 1-3 presents the learning rates that the Project Team applied to each of these categories. These learning rates represent the reduction in per unit costs associated with every doubling in the cumulative production of each respective technology.[8] Although innovation may lead to the development of new technologies that would reduce costs even further, we do not attempt to capture such effects in the cost estimates presented in this report. The learning rates presented in Exhibit 1-3 only reflect the cost-reducing impact of firms' growing experience with existing technologies.

Exhibit 1-3. Learning Rates and Cumulative Production Metrics for EGU Emission Control Technologies and Motor Vehicle Emission Controls

Control Technology/ Source Category	Learning Rates	Cumulative Production Metric
Flue Gas Desulfurization[1]	Capital Costs: 11% O&M Costs: 22%	Cumulative FGD capacity.
Selective Catalytic Reduction[2]	Capital Costs: 14% O&M Costs: 21%	Cumulative SCR capacity.
Selective Non-catalytic Reduction[3]	Capital Costs: 15% O&M Costs: No adjustment	Cumulative number of plants with SNCR.
Motor Vehicle Engine Controls[4]	Fixed Production Costs: No Adjustment Variable Production Costs: 13% Vehicle Operating Costs: No adjustment	Cumulative vehicle production

Notes:
1. Estimates for FGD from Edward S. Rubin, Sonia Yeh, David A. Hounshell, and Margaret Taylor. "Experience curves for power plan emission control technologies," International Journal of Energy Technology and Policy, Vol. 2, Nos. 1/2, 2004.
2. Estimates for SCR derived from Sonia Yeh, Edward Rubin, Margaret Taylor, and David A. Hounshell. "Technology Innovation and Experience Curves for Nitrogen Oxides Control Technologies," Journal of the Air & Waste Management Association, Vol. 55, December 2005.
3. Estimate for SNCR derived from Cynthia Manson, Matthew B. Nelson, and James E. Neumann. "Assessing the Impact of Progress and Learning Curves on Clean Air Act Compliance Costs," unpublished working paper, July 2002.
4. Average of two estimates presented in Nicholas Baloff, "Extension of the Learning Curve--Some Empirical Results," *Operational Research Quarterly*, Vol. 22, No. 4, December 1971 and Dennis Epple, Linda Argote, and Rukmini Devadas, "Organizational Learning Curves: A Method for Investigating Intra-plant Transfer of Knowledge Acquired Through Learning by Doing," *Organizational Science*, Vol. 2, No. 1, February 1991.

Overview Of Model Sets

AirControlNET is used in this study to estimate the costs of attaining ozone and PM National Ambient Air Quality Standards (NAAQS), and to estimate costs for Federal non-EGU point and nonpoint source controls. AirControlNET is a control strategy and costing analysis tool developed by EH Pechan for EPA's Innovative Strategies and Economics Group. AirControlNET was designed for conducting

[8] The metric of cumulative production selected for each technology is consistent with that used in the underlying learning curve study.

analyses of air pollution regulations and policies, specifically development and implementation of NAAQS for criteria pollutants.

AirControlNET is a relational database system that links control technologies and pollution prevention measures to EPA emission inventories. The output of this linkage is a database of control measures and cost information for reducing the emissions of criteria pollutants as well as mercury from point (EGU and non-EGU), nonpoint, nonroad, and mobile sources as provided in EPA's National Emissions Inventory (NEI).

The control measure data files in AirControlNET include the pollutant control efficiency to calculate emission reductions for specific sources within the NEI, and also direct compliance cost data (annual operating and capital) to calculate the total costs of applying each control measure to specific sources. AirControlNET contains an extensive accounting for pollution control measures available across sources and the AirControlNET database currently contains more than 500,000 emission control records. Further details on the AirControlNET database can be found in Appendix G.

Electricity generating unit (EGU) control costs are estimated using the Integrated Planning Model (IPM).[9] 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). The IPM is an EPA model that provides cost estimates for CAAA-related NO_x and SO_2 controls at EGUs. Using forecasts for the electric power industry in 2010 and 2020, the IPM is designed to estimate emissions and control costs under specified control scenarios. Further information on IPM can be found at the following website: http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html.

Cost Accounting

The costs presented in this analysis are expressed as total annualized costs (TAC) in 2000, 2010, and 2020. Annualized costs include both capital and operation and maintenance (O&M) costs. Certain CAAA provisions require affected sources to invest capital in control equipment. In order to make appropriate comparisons of costs in 2000, 2010, and 2020, it is necessary to annualize costs over the period during which costs will be incurred (i.e., their equipment life) rather than including the total capital investment in the cost accounting. To annualize capital costs over a given equipment life, a discount rate of 5 percent is used. The annualization of capital costs allows for the conversion of total capital investment over a given time period to a uniform series of annual costs having the same present value as the total investment. After annualizing the capital investment for a particular control strategy, annualized capital costs are then added to the annual O&M costs to yield an estimate of the CAAA-related control costs in each of the years relevant to this analysis (2000, 2010 and 2020).

The control cost estimates from regulatory documents that used a discount rate of 7 or 10 percent were recalculated for consistency with the 5 percent discount rate assumption. For a few VOC source categories, EPA estimated that capital investment would not be necessary; and that compliance costs reflect O&M costs only. In these cases, the discount rate assumption has no effect on costs. For control measures whose costs are dominated by capital, rather than O&M costs, the annualized cost estimate is

[9] The Project Team used Version 2.1.9, updated with fuel and emission control technology data from AEO 2005. The version we used incorporates most of the technology data reflected in the latest EPA Base Case 2006, but retains the target years of 2007, 2010, 2015, and 2020 of Version 2.1.9. See Chapter 3 for more details.

more sensitive to the discount rate assumption than controls whose costs are primarily operating cost increases. Sensitivity analysis examining the effect of alternative discount rates (specifically, 3 and 7 percent) will be presented in a separate report on uncertainties in the overall study.

Summary Of Results

In this section we summarize the compliance cost analysis results by provision. The control measures included in this analysis reflect any post-1990 regulations promulgated after passage of the 1990 CAAA. Wherever possible, efforts were made in this analysis to make the cost results consistent with the emission projections analysis. In general, the emissions analysis and this cost analysis reflect all of the regulations that were promulgated before September 2005, when most of the emission projections were completed. Cost information for new regulations that were not modeled in the emission projections analysis are not included in this report in an effort to make the costs and benefits analyses as consistent as possible. This chapter includes a summary of the provisions included in this analysis and a summary of costs by provision under Titles I through IV.

Exhibit 1-4 summarizes the estimated costs of the 1990 CAAAs by title and major provision for the three analysis years: 2000, 2010 and 2020. This table shows that the direct compliance costs in 2000 are estimated to be about $20 billion and that these costs are dominated by the costs of motor vehicle-related provisions of the 1990 CAAAs as well as 1-hour ozone NAAQS and PM-10 NAAQS attainment costs. By 2000, about $1 billion per year was spent by firms complying with Title III National Emission Standards for Hazardous Air Pollutants. The major components of motor vehicle-related control costs in 2000 are for emission standards, fuel standards, and vehicle emission inspection programs in nonattainment areas. Motor vehicle emissions standard costs in 2000 are primarily for Tier 1 tailpipe standards, onboard diagnostics, and low emission vehicle programs (Cal-LEV and NLEV). Prominent motor vehicle fuel control programs in 2000 include Federal and California reformulated gasoline. These two reformulated gasoline programs are focused primarily in serious, severe and extreme 1 hour ozone NAAQS nonattainment areas.

Exhibit 1-4 shows that the estimated costs of complying with 1990 CAAA provisions are expected to more than double between 2000 and 2010 as areas develop and implement 8 hour ozone and PM-2.5 NAAQS State Implementation Plans (SIPs). One of the major cost components of the 2010 cost estimate is the estimated cost to reduce ozone precursor emissions to the level needed to demonstrate 8 hour ozone NAAQS attainment. This analysis estimates 8-hour ozone compliance costs in two components. One represents the cost of applying known and commercially available control technologies in nonattainment areas by the attainment date.

The second component is an estimated cost for applying controls to reduce emissions where there may not be enough known measures in the control strategy solution set to demonstrate attainment. For this draft, the cost of these unknown controls was estimated using a $10,000 per ton control cost; that estimate is provided below the main results. There is considerable uncertainty in this cost component because we do not know how individual areas will approach this issue; in the current draft, we have therefore reported these results separately from our primary results.

Exhibit 1-4 cost estimates for 2020 are similar to those estimated for 2010 for many CAAA provisions. Programs with significant cost increases between 2010 and 2020 nationally include motor vehicle fuels (nonroad diesel fuel sulfur limits begin in this time period), NAAQS compliance in the areas with the most severe nonattainment problems, and the Clean Air Visibility Rule (CAVR). The total annualized cost increase from 2010 to 2020 is about $5 billion. Some of this increase is directly related to growth in expected vehicle populations and associated fuel consumption.

Exhibit 1-4 provides additional information about the motor vehicle program costs in 2000, 2010 and 2020 by provision. Year 2000 motor vehicle costs that are borne by vehicle purchasers throughout the United States include Tier 1 emission standards, onboard diagnostics, and low emission vehicle programs (Cal-LEV and NLEV). Costs of reformulated gasoline and vehicle emission inspection programs are incurred primarily in the areas with the worst 1 hour ozone nonattainment problems.

Many new motor vehicle control programs are initiated in the 2000 to 2010 period and these include Tier 2 tailpipe standards, gasoline fuel sulfur limits, new heavy-duty emission standards, and associated diesel fuel sulfur limits. This leads to a near doubling of motor vehicle control program costs during this period. Motor vehicle control program costs in 2020 are nearly the same as in 2010 because we are not aware of specific new emission or fuel standards that may affect emissions and costs during this period.

Exhibit 1-4 summarizes nonroad engine/vehicle program costs in 2000, 2010 and 2020. Estimated costs of nonroad engine standards are much less than motor vehicle control costs, but still significant. Estimated national costs for nonroad control programs total about $250 million in 2000 and rise to about $1.3 billion in 2010. Note that costs for Phase 1 small spark ignition and Tier 1 diesel standards are zero in 2010 and 2020 because more stringent standards replace the lower tier standards, and therefore, no Phase 1 or Tier 1 engines are sold in 2010. Similarly, Tier 2 and 3 diesel engine standards no longer apply in 2020, so no associated costs are reported in 2020. In 2020, nonroad engine control costs are dominated by the cost to meet the Tier 4 and nonroad diesel low sulfur fuel standards. These two rules together represent over 80 percent of the 2020 nonroad sector cost of $2.4 billion.

The total cost of the CAAAs of 1990 shown in Exhibit 1-4 compare favorably with the cost estimate made for 2000 in the First Section 812 Prospective analysis, but the estimated cost of the Amendments in 2010 for this study is considerably higher than the corresponding First Prospective estimate. (The First Prospective estimated a 2000 annual cost of $19.4 billion and a 2010 cost of $26.8 billion.) The current 2000 cost analysis has a higher cost estimate for motor vehicle provisions, but lower cost estimates for PM-10 NAAQS compliance and Title IV—Acid Rain Provisions. Estimated 2000 costs for most of the other provisions are comparable.

The second Prospective cost estimates for 2010 are higher than those estimated for the first Prospective mainly because there are many Federal motor vehicle control programs that have been promulgated since the first Prospective was completed, plus we are now including the costs of meeting the 8 hour ozone, PM-2.5 NAAQS and Clean Air Visibility Rule requirements in that year.

As indicated above, the cost estimates presented in Exhibit 1-4 reflect the Project Team's expectations about the extent to which learning curve impacts will reduce the costs of CAAA provisions affecting motor vehicles and electric utilities. Because of these learning curve adjustments, the aggregate cost estimates in Exhibit 1-4 are 6 percent lower than they would be if we were to make no adjustments for learning. Among the provisions outlined in Exhibit 1-4, the impact of the Project Team's learning curve adjustments is most significant for the motor vehicle emission standards. If we had not accounted for learning curve impacts, our estimates of these costs would be 20 to 23 percent higher than the estimates presented in Exhibit 1-4. Similarly, costs for the California & National Low Emission Vehicle Programs would be approximately 13 to 14 percent higher. For utilities, our cost estimates for 2000 would actually be 1 percent lower had we not accounted for learning, while costs for 2010 and 2020 would be 1 to 5 percent higher.[10]

[10] Our electric utility cost estimates for 2000 would be higher because the cost equations supporting a significant portion of the cost estimates for 2000 apply to vintage 2004 capital equipment.

Exhibit 1-4. Summary of 1990 CAAA Compliance Costs by Title and Major Provisions

Provision	Annual Cost (Million 1999$)		
	2000	2010	2020
Title I and II Standards:			
National VOC Rules (Chapter 5)	250	291	353
Motor Vehicle/Fuels (Chapter 3)			
Motor Vehicle Emission Standards	3,751	6,468	6,575
Fuels	4,700	9,914	11,156
Nonroad Engines/Vehicle Standards	245	1200	2309
Area Specific (Chapters 5, 6, and 7)			
California and National LEV	610	2,197	2,236
Motor Vehicle I/M programs	3,813	5,098	5,933
RACT and New CTGs	689	787	950
NO_x SIP Call	6	116	118
Ozone Transport Commission Model Rules	102	159	204
Refinery Settlements	0	255	289
1-Hour Ozone NAAQS	884	1,030	1,030
PM_{10} NAAQS	130	130	130
8-Hour Ozone NAAQS	0	2,629	2,849
$PM_{2.5}$ NAAQS	0	751	542
Clean Air Visibility Rule	0	0	996
Title III-MACT Standards (Chapter 5)	1,152	2,547	2,547
Title I and IV-EGU Standards (Chapter 2)	1,154	5,583	8,911
TOTALS	**17,486**	**39,155**	**47,128**
Additional Estimated Costs for Unidentified Controls (Partial, at $10,000/ton):			
Residual 8-Hour Ozone Reductions (Chapter 7)			
Non-California areas	0	6,750	6,800
California areas	0	209	2,925

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CHAPTER 2 - ELECTRIC GENERATING UNIT POINT SOURCE ANALYSIS

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.[11] Exhibit 2-1 outlines the EGU-related regulations and programs established under the Amendments.

The purpose of this chapter is to describe the 812 project team's approach for estimating the costs incurred by electric utilities as a result of the Clean Air Act Amendments and to present the project team's estimates of these impacts during the 1990-2020 period. 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 the CAAA-related costs incurred by utilities relative to other sources. According to EPA's First Prospective Analysis of the Clean Air Act, electric utilities are expected to incur approximately 17 percent of the total costs associated with the Amendments in 2010.[12]

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[11] 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.

[12] U.S. EPA, *The Benefits and Costs of the Clean Air Act 1990 to 2010*, November 1999, EPA-410-R-99-001.

Exhibit 2-1. CAAA-Related Rules and Programs Reflected in Section 812 EGU Cost and Emissions Analyses
• 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,[13] • 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).

We present the project team's methodology and results in four separate sections.

1. ***Analytic Tools:*** First, we provide a detailed description of the analytic tools and methods the project team used to estimate the costs incurred by EGUs as a result of the Amendments.

2. ***Application of IPM for the 2010 and 2020 Target Years:*** In the second section we describe the project team's cost analysis for the 2010 and 2020 target years.

3. ***Application of IPM for 2000 Target Year:*** The third section of this chapter outlines the project team's application of IPM for the 2000 Section 812 target year. We present this information separately from our application of IPM for 2010 and 2020 because the project team's approach for estimating costs retrospectively is different than its approach for projecting costs into the future.

4. ***Results:*** To conclude the chapter, we present the project team's cost estimates for 2001, 2010, and 2020. Although 2000, 2010, and 2020 represent the target years selected for the Second Prospective, the project team uses EGU costs in 2001 as a proxy for costs incurred in 2000.[14]

[13] 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 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.

[14] Before commencing with the cost analysis for the Second Prospective, EPA conducted an analysis of EGU costs and emissions in 2001 to test the accuracy of the analytic tools that EPA typically uses for EGU cost and emission analyses. Due to resource constraints, the project team expanded upon this analysis for the Second Prospective rather than developing an entirely new EGU cost and emissions analysis for 2000.

Because the project team uses the same economic model to assess both EGU cost and emissions impacts, much of the material included in the following sections is also presented in the Second Prospective emissions report previously submitted to EPA's Advisory Council on Clean Air Compliance Analysis.[15]

Analytic Tools

To estimate the costs incurred by electric utilities as a result of the Amendments, the 812 project team adapted cost estimates generated by ICF Resource's Integrated Planning Model (IPM). In this section, we summarize IPM's capabilities and describe how the project team modified IPM's results to generate cost estimates consistent with the analytic requirements and assumptions of the Second Prospective.

IPM

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). Below we outline 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.

IPM Structure, Features, and Assumptions[16]

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 individual generating units, 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.

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

[15] E.H. Pechan & Associates, Inc. and Industrial Economics, Inc. *Emissions Projections for the Clean Air Act Second Section 812 Prospective Analysis*, prepared for James DeMocker, U.S. EPA Office of Air and Radiation, June 2006.

[16] 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.

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.[17] 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 made during prior years included in the model's time horizon, such as 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 projections of electricity demand, IPM includes a series of seasonal load duration curves specific to each region and 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.

To capture the dynamics of the SO_2 and NO_x allowance markets, IPM models the banking of allowances not used by utilities for each model run year. Allowances allocated but not used during any given model run year can be used in future years. The model, however, includes no explicit assumptions regarding the initial allocation of allowances among individual generating units. Instead, the model distributes allowances to units such that the net present value of electricity production costs incurred over the model's time horizon is minimized, taking into account the various constraints that are included in the model. The costs associated with this approach are likely similar to those associated with an auction-based allocation system. Although EPA issues some emission allowances through auctioning, the majority of allowances are allocated to units based on their historical heat input. Several studies have suggested that such an allocation system is less efficient than auctioning allowances.[18] Therefore, IPM may underestimate the costs of the EGU emissions requirements established under the Amendments, although the magnitude of such underestimation is uncertain.

As part of its modeling of allowance markets, IPM captures allowances banked before the model's time horizon. For the model runs supporting the 2010 and 2020 cost analyses, IPM assumes that 5 million tons of SO_2 allowances were banked before the IPM planning horizon (e.g., before 2007) and that utilities could drawn upon these allowances to meet the requirements of the Amendments. Although IPM can also account for previous banking of NO_x allowances, the model assumes that no NO_x allowances were banked prior to 2007. For the 2001 with-CAAA IPM model run, the project team's configuration of the model includes no explicit simulation of allowance banking or the use of allowances banked before 2001. Instead, emissions for the 2001 run were constrained to reflect actual emissions observed in 2001. We do not believe that this limitation of the model run has a significant impact on our 2001 cost estimates because actual 2001 emissions would reflect any allowance banking or use of allowances that occurred in 2001.

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[17] IPM also generates results for 2026, the last model run year included in the model. To avoid boundary distortions, however, EPA does not typically report the results for this year.

[18] These studies include Alan J. Beamon, Tom Leckey, and Laura Martin. 2001. “Power Plant Emission Reductions Using a Generation Performance Standard,” Energy Information Administration, Draft Working Paper March 19, 2001; Karen Palmer and Dallas Burtraw, "Distribution and Efficiency Consequences of Different Approaches to Allocating Tradable Emission Allowances for Sulfur Dioxide, Nitrogen Oxides and Mercury," RFF Discussion Paper, January 2004; and Dallas Burtraw, Karen Palmer, Ranjit Bharvirkar, and Anthony Paul, "The Effect of Allowance Allocation on the Cost of Carbon Emission Trading," RFF Discussion Paper, August 2001;

IPM Outputs

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

Costs: Based on the 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 the aggregate and at the unit level. In addition, although IPM is not designed to report costs for individual emission control retrofit technologies (e.g., flue gas desulfurization, selective catalytic reduction, selective non-catalytic reduction, etc.), such information can be extracted from the unit level results generated by the model.

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 the 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. IPM's outputs with respect to capacity and generation also include capacity by control technology (e.g., flue gas desulfurzation, etc.).

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.

Augmenting and Adjusting Cost Estimates Generated by IPM

To develop EGU cost estimates consistent with the analytic requirements and assumptions of the Second Prospective, the project team made three modifications to the cost estimates generated by IPM. First, to augment IPM's cost estimates, the project team estimated the capital costs associated with investments made between 1990 (the year the Amendments were enacted) and the first year of IPM's model time horizon.[19] As indicated above, IPM's capital cost estimates do not reflect these costs. Second, because the interest rates included in IPM are inconsistent with the 5 percent discount rate chosen for the Second Prospective, the project team adjusted IPM's capital cost estimates to reflect the 5 percent rate. Third, because IPM's cost projections for individual pollution control technologies do not reflect the cost-reducing effects of learning curve impacts, the project team adjusted IPM's cost projections to account for these impacts.[20] We describe all three of these adjustments in more detail below.

[19] This time horizon is 2007-2030 for the IPM model runs supporting the cost estimates for 2010 and 2020. For the 2001 IPM analysis, the model time horizon is limited to 2001.

[20] These learning curve adjustments reflect firms' growing experience with existing technologies (e.g., flue gas desulfirzation) but not the development and introduction of new control technologies that might reduce the costs of complying with the Amendments.

Costs Related to Investments Made Prior to the IPM Time Horizon

As described above, IPM is a forward-looking model that optimizes utilities' dispatch and investment decisions. Although IPM estimates the costs of capital investments made by utilities during the time period reflected in the model, it does not estimate the sunk costs of investments in emission controls that predate the model's time horizon because such costs have no bearing on future EGU decision-making. Therefore, the model does not capture a significant portion of the capital costs associated with the Amendments (i.e., capital costs associated with investments made between 1990 and the beginning of IPM's planning horizon). For the IPM analysis supporting the 2010 and 2020 EGU analyses, IPM's planning horizon includes the years 2007 through 2030. As indicated above, the project team used the results of an IPM run for 2001 as a proxy for EGU costs in 2000. The time horizon of this analysis was limited to the year 2001.

Because IPM does not estimate the capital costs associated with investments made between 1990 and the beginning of the model's time horizon, the project team estimated these costs based on the operating characteristics of individual generating units. Ideally, these estimates would reflect the costs associated with sunk investments in abatement capital (i.e., emissions control devices and investments in capital for transitioning to low-sulfur coal) and new generating capacity. While we estimate costs related to the former, we do not estimate capital costs related to the latter due to resource and data limitations. To the extent that investment in new capacity would have been different in the absence of the Amendments than under the with-CAAA scenario between 1990 and the beginning of the IPM time horizon, this could bias our estimates of the incremental capital costs associated with the Amendments.[21] More specifically, if the Amendments encouraged a shift toward the construction of gas-fired or combined cycle capacity instead of coal-fired units, capital costs associated with new generating capacity could have been different under the without-CAAA scenario than under the with-CAAA scenario.[22] We believe, however, that the potential for such bias is minimal. Although investment in gas-fired and combined cycle units has been significant since the passage of the Amendments, these investments largely reflect economic forces unrelated to the Amendments, such as relatively low natural gas prices in the 1990s and the development and availability of more efficient combined-cycle generating technology.[23] Therefore, we assume that investments in new generating capacity made between 1990 and the beginning of the IPM time horizon would have been the same in the absence of the Amendments as under the with-CAAA scenario and focus our analysis on EGU investments in abatement capital.

Investments in Emission Control Devices Prior to the IPM Time Horizon

Emission control devices represent an important part of the abatement capital installed before the IPM time horizon. These devices include flue gas desulfurization (FGD) systems, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR). Because the IPM analysis supporting the

[21] The IPM results, which cover the 2007-2020 period, reflect the difference between with-CAAA and without-CAAA capacity investments during this period.

[22] In addition, our results may be biased if more capacity had been added under the without-CAAA scenario than under the with-CAAA scenario. However, because we assume that electricity demand is the same under both the with-CAAA and without-CAAA scenarios, we also assume that the difference between with-CAAA and without-CAAA capacity additions predating the IPM time horizon is minimal.

[23] This is consistent with the characterization of investments in natural gas units presented in Carlson, Curtis, Dallas Burtraw, Maureen Cropper, and Karen L. Palmer, "Sulfur Dioxide Control by Electric Utilities: What Are the Gains from Trade?" *Journal of Political Economy*, 2000, Vol. 108, No. 6; and A. Denny Ellerman and Florence Dubroeucq, "The Sources of Emission Reductions: Evidence from U.S. SO_2 Emissions from 1985 through 2002," working paper, MIT Center for Energy and Environmental Policy Research, January 2004.

project team's analysis for 2010 and 2020 does not estimate the costs associated with emission control devices installed between 1990 and 2006, the project team estimated these costs using two separate procedures: one for the with-CAAA scenario and another for the without-CAAA scenario.[24] For the with-CAAA scenario, the project team first identified all of the pollution control systems believed to be operating at EGUs in 2006.[25] We identified these systems using version 2.1.9 of EPA's NEEDS database, which underlies the version of IPM that the project team used for the Second Prospective.[26] Based on the capacity and other operating characteristics of each pollution control device identified in NEEDS, the project team then estimated the annualized capital costs associated with each device using the cost equations included in IPM. For the without-CAAA scenario, the project team followed a similar procedure, starting with the identification of EGU emission controls believed to be in place in 2006. However, instead of estimating the capital costs associated with all of these systems, we estimated the costs associated only with those devices necessary to meet the regulatory requirements that were in place when the Amendments were enacted in 1990.

As indicated above, the project team conducted a separate IPM analysis for 2001, using EGU costs in 2001 as a proxy for costs in 2000. Similar to the IPM analysis for 2010 and 2020, the 2001 analysis did not estimate the sunk costs associated with FGD, SCR, and SNCR installed before 2001, the first and only year in IPM's time horizon for the 2001 EGU analysis. Therefore, to supplement IPM's cost estimates for the 2001 analysis, we estimated the capital costs associated with emission control devices installed between 1990 and 2000 based on the estimate we developed for controls installed during the 1990-2006 period. More specifically, we used EPA's NEEDS 2000 and NEEDS 2004 databases to identify the FGD, SCR, and SNCR units installed between 2000 and 2006 that are reflected in the 1990-2006 estimate.[27][28] We then excluded the costs associated with these units from our 1990-2006 estimate to generate an estimate specific to emission control devices installed during the 1990-2000 period.

Investments in Fuel Switching Capital Prior to the IPM Time Horizon

In addition to end-of-pipe technologies to control emissions, several EGUs switched to low-sulfur coal prior to the IPM time horizon to meet the emissions requirements established under the Amendments. Although fuel switching is not a capital-intensive process, utilities that switch to low-sulfur coal typically invest resources in modifications to their boilers and handling equipment. To estimate the capital costs associated with such investments made prior to the IPM time horizon, we used the database underlying EPA's Clean Air Market Data and Maps system on the emissions, heat input, and capacity of EGUs included in Phase 1 and Phase 2 of the SO_2 emissions trading program established under Title IV of the Amendments.[29] The methodology that we developed based on these data is as follows:

1. ***Identify units that likely switched to low-sulfur coal prior to the IPM time horizon.*** Based on the EPA data, we estimated the annual SO_2 emissions rate for each Phase 1 and Phase 2 unit for

[24] As indicated above the time horizon for IPM's 2010/2020 analysis begins in 2007.

[25] Units believed to be online as of 2006 include units confirmed to be online in 2004 and additional units expected to be online by 2006.

[26] We also refer to NEEDS 2.1.9 as NEEDS 2004 throughout this chapter.

[27] The NEEDS 2000 and NEEDS 2004 databases are also known as NEEDS 2.1 and NEEDS 2.1.9, respectively.

[28] The NEEDS 2004 database includes units online in 2004 as well as capacity additions expected by 2006.

[29] U.S. EPA, Clean Air Markets Data and Maps, http://cfpub.epa.gov/gdm/index.cfm. Our analysis of these data was aided by prior collaboration with Dr. Denny Ellerman of the Massachusetts Institute of Technology (MIT).

the years 1991 through 2004. If a unit did not have a scrubber and experienced an emission rate reduction exceeding 0.5 pounds per million Btu from one year to the next, we assume that it switched to low-sulfur coal.[30] To identify fuel switching investments that predate the 2007-2030 time horizon of the IPM analysis for 2010 and 2020, we considered emission rates for the entire 1991-2004 period. Because the EPA data do not include emission rates for 2005 and 2006, we do not capture fuel switching investments made during these two years.[31] To identify units that engaged in fuel switching prior to 2001 (i.e., the single year included in the time horizon of the 2001 IPM analysis), we examined emissions rates between 1991 and 2000.

2. ***Estimate the annualized costs incurred by units that switched to low-sulfur coal prior to the IPM time horizon.*** For each unit identified in Step (1), we estimate the total cost of fuel switching based on a unit cost of $50 per kW of capacity controlled.[32,33] To annualize these costs, we used a discount rate of 5 percent and assumed a useful life of 30 years for fuel switching capital.[34]

3. ***Estimate fuel switching capital costs attributable to the Amendments.*** In Step (2) we estimated the total capital costs associated with *any* fuel switching likely to have occurred between the time the Amendments were enacted and the beginning of the IPM time horizon. Due to railroad deregulation and other factors that have reduced the cost of switching to low-sulfur coal, much of the fuel switching reflected in these costs may have occurred in the absence of the Amendments. To separate CAAA-related fuel switching costs from fuel switching costs that utilities would have incurred in the absence of the Amendments, we adapted the results of an econometric study published by Ellerman *et al.* in 2000. The results of this study suggest that approximately 52 percent of the fuel switching abatement occurring between 1995 and 1997 among units in Phase 1 of EPA's SO_2 trading program was attributable to the Amendments.[35] We applied this value to the Phase 1 fuel switching costs estimated in Step (2) to estimate the Phase 1 fuel switching costs associated with the Amendments. For units included in Phase 2 of the Title IV SO_2 program, we identified no studies estimating the extent to which abatement related to fuel switching reflected the impact of the Amendments rather than railroad deregulation and other factors that reduced the cost of fuel switching in the 1990s. In the absence of such a study, we applied the 1997 results of the Ellerman Phase 1 analysis to the Phase 2 costs estimated in Step (2). These results indicate that 49 percent of the Phase 1 fuel switching abatement in 1997 was related to the Amendments. We did not apply Ellerman's Phase 1 results for the entire 1995-1997 period to Phase 2 units because the second phase of the SO_2 trading program did not begin until 2000. We believed that

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[30] This 0.5 pounds per million Btu threshold represents the outer bound of normal SO_2 emission rate variability from one year to the next as estimated in A. Denny Ellerman, Paul L. Joskow, Richard Schmalensee, Juan-Pablo Montero, and Elizabeth M. Bailey, *Markets for Clean Air: The U.S. Acid Rain Program*, Cambridge University Press, 2000.

[31] Data for 2005 were not available until we had made significant progress on our analysis.

[32] This unit cost value represents the capital costs associated with switching to low-sulfur coal from Wyoming's Powder River Basin, as reported in Ellerman, *op cit*.

[33] For units without capacity data available, we used the average capacity of the units identified in Step (1) for which capacity data are available, using separate averages for Phase 1 and Phase 2 units.

[34] This useful life assumption is consistent with that used in IPM for emission abatement capital.

[35] This econometric analysis is summarized in Ellerman, *op cit.* Based on the results of this analysis, Ellerman *et al.* estimate that fuel switching reduced EGU SO_2 emissions by 14.4 million tons between 1995 and 1997, 7.5 million tons of which was related to Title IV of the Amendments.

the Phase 1 results for 1997 would better represent conditions in 2000 than the results for the entire 1995-1997 period.

IPM Discount Rate Adjustments

To annualize the costs and benefits associated with the Amendments, the 812 project team is using a social discount rate of 5 percent, consistent with the discount rate used in EPA's Retrospective and First Prospective Analyses of the Clean Air Act.[36] The interest rates included in IPM are estimates of the cost of capital and are inconsistent with this 5 percent rate. As indicated in Exhibit 2-2, IPM uses interest rates ranging from 5.34 percent to 6.74 percent to reflect differences in risk between different classes of investments and therefore represent the cost of capital. These rates are appropriate for the purposes of modeling utility compliance behavior, but not for discounting in a social welfare analysis. To generate EGU capital cost estimates that are consistent with the 5 percent discount rate chosen for the Second Prospective, the 812 project team de-annualized IPM's capital cost values based on the interest rates included in the model and re-annualized them using the 5 percent discount rate.

Exhibit 2-2. IPM Interest Rate and Useful Life Assumptions

Investment Type	Interest Rate	Useful Life	Capital Charge Factor
Low-risk investments	5.34 percent	30 years	0.12
Medium-risk investments	6.14 percent	30 years	0.129
High-risk investments	6.74 percent	30 years	0.134

Source: U.S. EPA, *Standalone Documentation for EPA Base Case 2004 (V.2.1.9) Using The Integrated Planning Model*, EPA 430-R-05-011, September 2005.

To adjust IPM's annualized capital costs to reflect the 5 percent discount rate chosen for the Second Prospective, the 812 project team followed the three-step procedure outlined below.

1. **De-annualize the annual capital cost estimates generated by IPM.** The 812 project team de-annualized IPM's annual capital cost estimates based on the following formula:

(1) $$T = \frac{A}{CCF}$$

where A = Annualized capital costs as estimated by IPM
T = Total cost of capital assets, including installation
CCF = Capital charge factor

The 812 project team applied Formula 1 to the annual capital cost estimates associated with each of the three classes of investments included in IPM (i.e., low-risk, medium-risk, and high-risk investments). As indicated in Exhibit 2-2, IPM applies different capital charge factors to different classes of investment. IPM estimates the capital charge factor as the sum of two values: (1) the capital recovery factor that corresponds to the interest rate for a specific class of investment and

[36] The project team's rationale for choosing this rate is presented in Jim DeMocker, U.S. EPA. Memorandum to the 812 Prospective II Files, July 29, 2005.

(2) a capital recovery factor adder of 0.03 that reflects property taxes, insurance, and working capital interest.[37,38]

2. **Estimate re-annualized capital costs excluding taxes, insurance, and working capital interest.** Based on the total capital cost estimates generated in step 1, the 812 project team re-annualized the IPM capital cost estimates using the 5 percent discount rate selected for the Second Prospective. Formula 2 outlines how the project team performed these calculations.

$$(2) \quad A = \frac{T}{\frac{1}{r} - \frac{1}{r(1+r)^n}}$$

where A = Annualized capital costs
T = Total cost of capital assets, including installation (estimated in step 1)
r = discount rate (5 percent)[39]
n = Useful life of the asset

The results based on Formula 2 represent the annualized capital cost estimates for the Second Prospective. Unlike the estimates included in IPM's standard outputs, these estimates only reflect the cost of capital equipment itself; they do not capture the fixed operating and maintenance costs associated with the equipment (i.e., property taxes, insurance, and working capital interest).

3. **Estimate annual insurance and working capital interest costs.** As indicated above, the annualized cost estimates generated in step 2 do not reflect costs associated with property taxes, insurance, or working capital interest. For the Second Prospective, the 812 project team includes insurance and working capital interest in its cost estimates but not property taxes. Because property taxes represent a transfer of resources from one party to another rather than an expenditure of resources, it would not be appropriate to include property taxes in the cost estimates for the Second Prospective. Although insurance may also represent a transfer (between insured parties), payments to insurance claimants represent the real resource expenditures necessary to repair or replace equipment damaged from fires, tornadoes, and other insured events. The value of these losses represent incremental costs associated with compliance with Clean Air Act requirements. Insurance premiums reflect the expected value of these expenditures and the administrative cost of managing individual insurance policies. Therefore, the project team includes insurance as a cost in the Second Prospective.

   Information obtained from EPA staff indicates that one third of the 0.03 capital recovery factor adder included in IPM reflects insurance and working capital interest costs.[40] Therefore, to estimate insurance and working capital interest costs for the Second Prospective, the project team

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[37] The capital recovery factor for a given interest rate, *i*, for a capital investment with a useful life of *t* years is $\frac{i(1+i)^n}{(1+i)^n - 1}$. Multiplying this value by the total cost of a capital asset yields the annualized cost of the asset.

[38] We obtained the 0.03 estimate for the capital recovery factor adder from Chitra Kumar, U.S. EPA Office of Air and Radiation, December 23, 2005.

[39] The 812 project team will also perform sensitivity analyses using a 3 percent discount rate and a 7 percent discount rate.

[40] Personal communication with Chitra Kumar, U.S. EPA Office of Air and Radiation, December 23, 2005.

will multiply the total capital cost estimates generated from step 1 by 0.01. The project team will add these costs to the fixed operating and maintenance cost estimates generated by IPM.

Exhibit 2-3 presents an example of our proposed three-step adjustment approach for a low-risk capital investment.

Exhibit 2-3. Example of IPM Capital Cost Adjustment Procedure

Step/Calculation	Value
Annualized Capital Cost for Low-risk Investments, as Reported by IPM	$10 million
Total (De-annualized) Capital Costs for Low-risk Investments	$83.3 million[1]
Annualized Capital Costs Based on 5 Percent Discount Rate and 30-year Useful Life (excluding insurance, property taxes, and working capital interest)	$5.42 million
Annual Insurance and Working Capital Interest Costs (1 percent of total capital cost)	$0.83 million[2]

Notes:
1. Based on $10 million in annualized capital costs and a capital charge factor of 0.12 for low-risk investments, as presented in Exhibit 2-2.
2. Property taxes excluded because they represent a transfer rather than a real resource expenditure.

Adjusting EGU Cost Estimates to Account for Learning Curve Impacts

A key limitation of the cost projections developed by IPM is that they do not reflect the cost-reducing effect of learning curve impacts. For example, IPM assumes that the cost of a flue gas desulfurization (FGD) unit installed in 2010 is the same as that of a comparable FGD unit installed in 2020. Several studies suggest, however, that the costs of FGD and other pollution control technologies decline as the adoption of these technologies increases. Based on the findings of these studies, the 812 project team adjusted IPM's 2010 and 2020 cost projections for FGD, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR) retrofits to account for learning curve impacts.

Consistent with several learning curve analyses in the academic literature, we adjust IPM's retrofit cost projections for FGD, SCR, and SNCR based on the equation presented below.[41]

(3) $y_i = ax_i^{-b}$

where y_i= Costs of controlling the i^{th} ton of NO_x (for SCR and SNCR) or SO_2 (for FGD) emissions;

[41] Examples of such analyses include John M. Dutton and Annie Thomas, "Treating Progress Functions as a Managerial Opportunity," *Academy of Management Review*, 1984, Vol. 9, No. 2, 235-247; International Energy Agency, *Experience Curves for Energy Technology Policy*, 2000; Pietro Peretto and V. Kerry Smith, "Carbon Policy and Technical Change: Market Structure, Increasing Returns, and Secondary Benefits," report prepared for the U.S. Department of Energy under grant DE-FG02-97ER62504, November 19, 2001.

x_i= Cumulative capacity of a control technology when the i^{th} ton of NO_x or SO_2 emissions is controlled;
b= learning curve exponent, and
a= input cost for the first ton of emissions controlled.

Based on Formula 3, each doubling in the cumulative capacity of a retrofit technology corresponds to a cost savings of $(1-2^{-b})$ percent per ton of emissions controlled, which we refer to as the learning rate. Exhibit 2-4 presents the learning rates that we use for FGD, SCR, and SNCR retrofits. We provide additional detail on the sources of these estimates below.

We apply the learning rates presented in Exhibit 2-4 to all of the FGD, SCR, and SNCR capital costs incurred by EGUs as a result of the Amendments and the O&M costs for FGD, SCR, and SNCR units installed at EGUs during the IPM planning horizon. Because of IPM's configuration, we were not able to separate the O&M costs associated with emission controls installed prior to the IPM time horizon from the other O&M costs estimated in the model. Therefore, we do not apply any learning curve adjustments to O&M associated with FGD, SCR, or SNCR installed before the IPM planning horizon.[42]

Exhibit 2-4. Learning Rates and Cumulative Production Metrics for EGU Emission Control Technologies

Control Technology	Learning Rates	Cumulative Production Metric
Flue Gas Desulfurization[1]	*Capital Costs*: 11% *O&M Costs*: 22%	Cumulative FGD capacity.
Selective Catalytic Reduction[2]	*Capital Costs*: 14% *O&M Costs*: 21%	Cumulative SCR capacity.
Selective Non-catalytic Reduction[3]	*Capital Costs*: 15% *O&M Costs*: No adjustment	Cumulative number of plants with SNCR.

Notes:
1. Estimates for FGD from Edward S. Rubin, Sonia Yeh, David A. Hounshell, and Margaret Taylor. "Experience curves for power plan emission control technologies," International Journal of Energy Technology and Policy, Vol. 2, Nos. 1/2, 2004.
2. Estimates for SCR derived from Sonia Yeh, Edward Rubin, Margaret Taylor, and David A. Hounshell. "Technology Innovation and Experience Curves for Nitrogen Oxides Control Technologies," Journal of the Air & Waste Management Association, Vol. 55, December 2005.
3. Estimate for SNCR derived from Cynthia Manson, Matthew B. Nelson, and James E. Neumann. “Assessing the Impact of Progress and Learning Curves on Clean Air Act Compliance Costs,” unpublished working paper, July 2002.

[42] We will consult with the developers of IPM before completion of the final Second Prospective Cost Report to explore the feasibility of conducting an analysis offline from IPM to separate these costs from the other O&M costs estimated by IPM.

Flue Gas Desulfurization (Scrubber) Retrofits

Our learning curve adjustments for FGD are based on the results of a 2004 study by Rubin *et al.* examining the relationship between FGD costs and cumulative worldwide generating capacity controlled by FGD (measured in gigawatts).[43] The results of this analysis suggest that FGD capital costs per kilowatt of controlled capacity decline by 11 percent with each doubling of cumulative installed FGD capacity. This decline reflects the cost-reducing impact of firms' increased experience in the production and application of FGD technology. The data sources supporting this analysis include FGD cost studies from the Tennessee Valley Authority (TVA) for the 1970s and 1980s and a series of FGD cost assessments conducted by the Electric Power Research Institute (EPRI) between the mid-1980s and the mid-1990s. In addition, the 11 percent rate reflects worldwide FGD capacity as reported by the International Energy Agency (IEA).

The Rubin *et al.* study also presents a preliminary estimate of the learning rate for FGD O&M costs. The authors characterize this rate as preliminary because the underlying cost data represent *expected* O&M costs for a standardized FGD system at different points in time rather than the O&M data related to specific FGD systems. Nevertheless, to the extent that the trend in expected O&M costs is consistent with actual changes in O&M costs over time, this trend could serve as a useful indicator of technological change. Using the expected O&M cost estimates as surrogate data for actual O&M costs, the authors estimated a learning rate of 22 percent for FGD O&M costs.

Based on the Rubin *et al.* study, we used a learning rate of 11 percent to adjust IPM's capital cost projections for FGD retrofits and a learning rate of 22 percent for FGD O&M costs. The extent to which we adjust the FGD capital cost projections for any given year reflects the vintage profile of the FGD systems in place that year. For example, FGD-related capital costs incurred by utilities in 2020 may reflect FGD units installed in 2010, others installed in 2015, and additional FGD units purchased by utilities in 2020. Therefore, in adjusting the annualized FGD capital cost estimate for 2020, we make separate learning curve adjustments for the capital costs associated with each vintage group--the first adjustment for units installed in 2010 would reflect cumulative FGD capacity in 2010, the second for units purchased in 2015 would reflect cumulative capacity in 2015, and the third adjustment for units installed in 2020 would reflect cumulative capacity in 2020.

Consistent with the Rubin *et al*. estimation of FGD learning curve impacts, we adjust IPM's FGD cost projections based on the cumulative generating capacity controlled by FGD worldwide. According to IEA data cited by Rubin *et al.* and Nolan, approximately 223.4 gigawatts (GW) of generating capacity were controlled by FGD in 2000.[44] Due to limitations in the readily available data, we only capture FGD installations made within the U.S. for the post-2000 period.[45] Based on data in EPA's NEEDS 2000 and NEEDS 2004 databases, we estimate that approximately 5.9 GW of generating capacity in the U.S. were

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[43] Edward S. Rubin, Sonia Yeh, David A. Hounshell, and Margaret Taylor. "Experience curves for power plan emission control technologies," *International Journal of Energy Technology and Policy*, Vol. 2, Nos. 1/2, 2004.

[44] This estimate reflects 198.4 GW of EGU capacity controlled by wet FGD and 25 GW of capacity controlled by dry FGD systems. The IEA data for wet FGD capacity was provided by Sonia Yeh, co-author of Rubin *et al.*, *op. cit.* The estimate for dry FGD is from IEA Coal Power 3, as cited in Paul S. Nolan, "Flue Gas Desulfurization Technologies for Coal-Fired Power Plants," The Babcock & Wilcox Company, U.S., presented by Michael X. Jiang at the Coal-Tech 2000 International Conference, November, 2000, Jakarta, Indonesia.

[45] Although it may be possible to project FGD capacity outside of the U.S., doing so would require extensive resources beyond the scope of this analysis.

fitted with FGD between 2000 and 2006.[46] For 2007 through 2020, we use IPM's results to estimate the additional U.S. capacity retrofitted with FGD. Because we do not capture post-2000 FGD capacity additions outside of the U.S., we may underestimate the learning impacts associated with FGD and overestimate the cost associated with this technology.

Selective Catalytic Reduction Retrofits

To adjust EGU cost impacts related to SCR retrofits, we use learning rates adapted from a recent study published by Yeh *et al.* in the *Journal of the Air & Waste Management Association.*[47] Based on SCR cost data from EPA, the Department of Energy, and EPRI, as well as coal-fired SCR capacity data from IEA, this study estimates that SCR capital costs per kilowatt of controlled capacity decline by 14 percent with every doubling in cumulative capacity controlled. Similarly, the study suggests that the learning rate for SCR O&M costs may be as high as 42 percent. This may be an overestimate, however, because the earliest cost values supporting this estimate were based on manufacturers' guarantees of a catalyst's useful life (typically a one-year catalyst life for US coal-fired plants). Later cost projections were revised because a catalyst's useful life was observed to be much longer than its guaranteed life, an apparent cost reduction that is unrelated to learning.

Based on the results of the Yeh *et al.* study, we apply a learning rate of 14 percent to IPM's estimates of SCR capital costs. Similar to our learning curve adjustments for FGD capital costs, we separate SCR capital costs by vintage and make separate learning curve adjustments for each vintage group. As described above, the Yeh *et al.* 42 percent learning rate for SCR O&M costs may over-estimate actual learning curve impacts. Nevertheless, because SCR is responsible for a significant portion of the EGU compliance costs associated with the Amendments, it is important that the project team capture the learning effects associated with this technology to the extent that the data allow. To guard against potential overestimation of learning effects while still capturing at least a portion of the learning curve impacts associated SCR operations and maintenance, we apply a learning rate of 21 percent (i.e., half the learning rate estimated by Yeh *et al.*) to SCR O&M costs.

Similar to our adjustments for FGD costs, we adjust SCR capital and O&M costs based on cumulative global generating capacity controlled by SCR. The IEA data used by Rubin *et al.* indicate that approximately 77.4 GW of generating capacity were equipped with SCR systems in 2000. Because we lack sufficient data to estimate changes in global capacity controlled after 2000, we use changes in U.S. capacity controlled to generate low-end estimates of the global capacity controlled after 2000. For example, we estimate that 69 GW of U.S. capacity were fitted with SCR between 2000 and 2006 based on data presented in EPA's NEEDS 2000 and NEEDS 2004 databases. Adding this value to the 77.4 GW of global capacity controlled in 2000, we use 146 GW as our estimate of global generating capacity controlled by SCR in 2006. Similar to our approach for FGD, we use IPM's results for the Second Prospective to estimate the additional U.S. capacity retrofitted with SCR by 2010 and 2020. The primary limitation of this approach is that we may underestimate the extent to which learning reduces the costs associated with SCR because we do not capture SCR installations outside of the U.S. after 2000.

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[46] As indicated above, NEEDS 2004 includes units online in 2004 as well as capacity additions expected to be online as of 2006.

[47] Sonia Yeh, Edward Rubin, Margaret Taylor, and David A. Hounshell. "Technology Innovation and Experience Curves for Nitrogen Oxides Control Technologies," *Journal of the Air & Waste Management Association*, Vol. 55, December 2005. Although the SCR cost data used in this study represent SCR systems at new plants rather than SCR retrofit systems, we base our learning curve adjustments for SCR retrofits on the results of this study under the assumption that the learning rate for SCR retrofits is similar to that of SCR systems at new plants.

Selective Non-catalytic Reduction Retrofits

Unlike our assessments of FGD and SCR learning curve impacts, our analysis of SNCR captures learning effects related to capital costs but not O&M. Although the cost of operating and maintaining SNCR systems may decline over time due to learning curve effects, we identified no studies quantifying the magnitude of such an effect. The only source that we identified with learning curve information specific to SNCR, a 2002 working paper by Manson *et al*., estimates that the cost of new SNCR units declines by 14 to 16 percent with each doubling in global SNCR installations, but does not estimate the learning rate for SNCR O&M costs.[48] Based on the 14 to 16 percent range presented in the Manson *et al.* study, we use a learning rate of 15 percent for SNCR capital costs. Similar to our learning curve adjustments for FGD and SCR capital costs, we make separate learning curve adjustments for different vintages of SNCR retrofits in use during a given year. For example, for SNCR capital costs in 2020, our learning curve adjustments for SNCR units installed in 2015 are more significant than our adjustments for units installed in 2010.

Because the SNCR learning rate estimated by Manson *et al.* reflects the relationship between SNCR capital costs and the cumulative number of SNCR installations worldwide, we use the latter as our metric of cumulative production. Based on data cited in Manson *et al.*, approximately 300 SNCR units had been installed globally by 2000.[49] For the 2001-2020 period, we were able to estimate the number of additional installations made within the U.S. (based on EPA's NEEDS databases and the results generated by IPM) but not installations made within other countries. Therefore, we may underestimate cumulative SNCR production after 2000 and, consequently, the extent to which learning may reduce the capital costs associated with units installed during this period.

New Electric Generating Units

For generating units projected to go online in the future, we make no adjustments to the associated costs estimated by IPM. IPM estimates these costs based on technology-specific unit cost values included in the Department of Energy's National Energy Modeling System (NEMS), which reflect DOE's assessment of the learning effects associated with individual technologies. In general, NEMS applies a ten percent learning rate to technologies during their infancy, a 5 percent learning rate to adolescent technologies, and a 1.0 percent learning rate to mature technologies.[50] The model classifies technologies as infant for their first three doublings of cumulative production, adolescent for the five subsequent doublings of cumulative production, and mature for remaining increases in cumulative production.[51] In addition, NEMS includes annual lower bound and upper bound learning limits for each generating technology. Lower bound learning rates vary by year and technology vintage (i.e., infant, adolescent, or mature), ranging from 0.65 percent for mature technologies in 2005 to 15.65 percent for infant technologies in 2020. For the upper bound, NEMS limits learning effects to the cost reduction associated with a 50 percent increase in cumulative production. Because DOE developed these estimates

[48] Cynthia Manson, Matthew B. Nelson, and James E. Neumann. "Assessing the Impact of Progress and Learning Curves on Clean Air Act Compliance Costs," unpublished working paper, July 2002. The authors developed the 14 to 16 percent estimate based on SNCR cost data from NESCAUM and EPRI and installation data from NESCAUM, *Environmental Regulation and Technology Innovation: Controlling Mercury Emissions from Coal-Fired Boilers*, September 2000.

[49] NESCAUM, *op. cit.*

[50] Etan Gumerman and Chris Marnay. "Learning and Cost Reductions for Generating Technologies in the National Energy Modeling System (NEMS)," January 16, 2004.

[51] *Ibid.*

based on historical cost and cumulative production data that it has collected over time, we believe that they are appropriate for inclusion in the Second Prospective.

Although learning effects may reduce the costs of new generating units over time, it is unlikely that IPM's treatment of these effects has a significant effect on the estimated incremental cost associated with the Amendments. As indicated above, we assume that electricity demand is the same under both the with-CAAA and without-CAAA scenarios and therefore that the Amendments have little, if any, effect on the need for new plants.

Learning Curve Adjustments for FGD, SCR, and SNCR Installed Before the IPM Planning Horizon

In addition to adjusting the cost projections generated by IPM to account for learning curve impacts, we made similar adjustments to the estimated capital costs associated with FGD, SCR, and SNCR installed before the IPM time horizon. As described above, we developed these estimates using the cost equations included in IPM. Because these equations are based on the cost of emission controls installed in 2004, they reflect pre-2004 learning curve impacts and may underestimate the capital costs associated with FGD, SCR, and SNCR installed before 2004. For example, a scrubber installed in 1998 would likely cost more than a comparable scrubber installed in 2004 because the cost of producing a scrubber likely fell during the 1998-2004 period due to the cost-reducing effect of learning. Therefore, a cost equation that represents the cost of scrubbers installed in 2004 would underestimate the cost of scrubbers installed in 1998. To account for this effect, we apply the FGD, SCR, and SNCR learning rates presented above to the estimated capital costs associated with emission control devices installed before the IPM time horizon.

Similar to our learning curve adjustments for IPM's cost projections, we use cumulative global capacity controlled as our cumulative production metric for FGD and SCR and the number of cumulative units installed as our cumulative production measure for SNCR. For FGD and SCR, the sources cited above provide sufficient data to estimate global capacity controlled during the 1990-2006 period.[52] However, 2000 is the earliest year for which we identified information on the cumulative number of SNCR units installed.[53] To estimate cumulative SNCR installations for earlier years, we extrapolated backward in time from our estimate of 300 units in 2000, based on the average number of units installed in the U.S. each year between 2000 and 2006. For example, data in EPA's NEEDS 2000 and NEEDS 2004 databases indicate that approximately 4 units were installed in the U.S. each year between 2000 and 2006. Based on this figure, we assume that 296 SNCR units had been installed globally as of 1999.

Because FGD, SCR, and SNCR capital cost estimates for units installed before the IPM planning horizon reflect installations at different points in time, we make separate learning curve adjustments for different vintages of retrofits reflected in the capital cost estimates. For example, we make only a minor adjustment for capital costs associated with FGD installed in 2003 (i.e., one year removed from the vintage year of IPM's cost equations) but a more significant adjustment for FGD installed in 1996.

Application of IPM For 2010 and 2020 Analyses

The results generated by IPM depend significantly on the regulatory scenario and data inputs included in the model. In this section we describe the with-CAAA and without-CAAA scenarios

[52] These sources provide capacity estimates for 1990, 1995, and 2000. We interpolate between the values for these years to estimate the capacity controlled in intermediate years.

[53] As indicated in NESCAUM, *op. cit.*, 300 SNCR units had been installed globally as of 2000.

developed by the 812 project team for the 2010 and 2020 IPM analyses and the core data inputs the project team included in the model. Because the project team's IPM analysis for the 2000 target year differs significantly from the 2010 and 2020 analyses, we present the project team's methodology for the 2000 IPM analysis in a separate section below.

Regulatory Scenarios for 2010 and 2020

To assess the emissions impact of the Clean Air Act Amendments for the years 2010 and 2020, we estimate emissions under two scenarios: a baseline scenario under which the Amendments remain in place (i.e., the with-CAAA scenario) and a counterfactual scenario that represents a regulatory environment absent the Amendments (i.e., the without-CAAA scenario). The difference between IPM's with-CAAA and without-CAAA costs represents the CAAA-related costs associated with EGU investments and operations during the IPM planning horizon. EGU capital costs for investments pre-dating the IPM planning horizon are estimated based on the methods outlined above.[54]

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,[55]
- 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 stringency. Exhibit 2-5 presents the emissions rates and other assumptions reflected in the without-CAAA scenario.

[54] Our analysis of capital costs associated with investments that pre-date the IPM planning horizon is separate from the IPM analysis conducted for the target year 2000. Due to model constraints that are unique to the 2000 run, the IPM analysis for 2000, which is described in detail below, does not estimate any EGU capital costs. Therefore, all capital costs associated with EGU emission control investments made between 1990 and 2007 are estimated external to IPM.

[55] 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 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.

Exhibit 2-5. 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— developed 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)
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.

Exhibit 2-5. Assumptions Reflected In The Without-CAAA Scenario		
Element		**Assumption**
	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)

Exhibit 2-5. Assumptions Reflected In The Without-CAAA Scenario	
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 analyses conducted for the Second Prospective reflect input data from several different sources. In some cases, the project team used 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 project team replaced the inputs in version 2.1.9 of the model 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 that 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 project team used the National Electric Energy Data System (NEEDS) 2004 database as its 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 2-6 and 2-7 summarize the sources of information EPA used to develop the NEEDS 2004 data for existing and planned/committed units, respectively.

Exhibit 2-6. 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 2004 (i.e., 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 2004 (i.e., 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 2004 (i.e., 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 2-7. 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 2.1.9 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.

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 812 project team retained the resource base and coal supply cost estimates included in version 2.1.9 of IPM but updated the coal supply productivity data in the model 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, the 812 project team also used AEO 2005 data for several other key model inputs. This application of AEO 2005 data is consistent with the project team's cost and 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;
- Life extension costs for fossil and nuclear power plants;
- Costs and technical specifications for new units (conventional and renewable);
- Nuclear availability and uprates,[56] and
- International energy imports.

In most cases AEO 2005 data were input directly into IPM; however, EPA adjusted the AEO 2005 projections of electricity demand to reflect EPA assumptions regarding future improvements in energy efficiency. These adjustments to AEO projections have been applied in other recent EPA analyses

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

http://www.nrc.gov/reactors/operating/licensing/power-uprates.html#definition, accessed June 20, 2006 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.[57]

Application of IPM for 2001 Analyses

As indicated in Chapter 1 of this report, the Second Prospective will estimate the impacts of the Amendments for the years 2000, 2010, and 2020. The previous section outlines the project team's approach for estimating costs incurred by electric utilities for the 2010 and 2020 target years. For 2000, the project team uses EGU costs in 2001 as a proxy for costs 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 costs and 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 recently promulgated 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 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 812 project team included the following data inputs in the model:

- IPM model units representing existing units were developed from the 2001 inventory of EGUs, as represented in NEEDS 2004.

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

- Electricity demand, peak load, and load shape were set to 2001 levels.[58] 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.[59]

- 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.[60] 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.[61]

- 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 assumes that controls installed at this time represent investments to limit emissions in 2002 and later years. The project team excluded scrubbers constructed in 2001 because no data indicating the month or season of installation were readily available.

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 cost and emissions estimates was consistent with the EGU capital stock in place in 2001. IPM, as a forward-looking model, does not estimate the capital costs associated with these sunk investments. Therefore, to estimate the capital costs of EGU emission control investments made between 1990 and 2001, we used the approach outlined above in the section named "Augmenting and Adjusting Cost Estimates Generated by IPM."

Results

Based on the methods and data outlined above, we estimated the CAAA-related costs incurred by EGUs as presented in Exhibit 2-8. As the exhibit indicates, we expect EGU costs to increase significantly between 2001 and 2010 and again between 2010 and 2020. This trend largely reflects the compliance deadlines for several rules affecting EGUs during the 2001-2020 period. For example, the Clean Air Interstate Rule, NO_x SIP Call, and the Clean Air Mercury Rule all have major compliance deadlines

[58] 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.

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

[60] 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.

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

between 2001 and 2010.[62] Similarly, both the Clean Air Interstate Rule and Clean Air Mercury Rule have additional compliance deadlines between 2010 and 2020.[63] In addition to these compliance deadlines, the upward trend in costs during the 2001-2020 period also reflects the expected increase in demand for electricity.

The results in Exhibit 2-8 indicate that NO_x controls (i.e., SCR and SNCR) make up a much larger portion of costs in 2010 and 2020 than in 2001. While we estimate that SCR and SNCR retrofits represented only 12 percent of EGU capital costs in 2001, our results suggest that they will represent between 32 and 39 percent of CAAA-related capital costs for EGUs in 2010 and 2020. The increased significance of SCR and SNCR retrofits in 2010 and 2020 most likely reflects the onset of several NO_x-related rules after 2001 such as the NO_x SIP Call and CAIR and the relatively high cost of NO_x controls.[64] Similarly, the sharp increase in costs associated with activated carbon after 2001 reflects EGU compliance with the Clean Air Mercury Rule, which sets a cap on EGU mercury emissions beginning in 2010. We also expect CAAA-related fuel costs to be significantly higher in 2020 than in 2010. This reflects a sharp increase in both natural gas prices and EGU natural gas consumption between 2010 and 2020. Although the Amendments are expected to increase natural gas prices and shift electricity production from coal to natural gas in 2001 and 2010, the results generated by IPM suggest that both of these effects will be much more pronounced in 2020 than in previous years.

To assess the extent to which the learning curve adjustments discussed above affect our estimates of EGU costs, we conducted a sensitivity analysis in which we excluded learning curve cost adjustments from the estimates presented in Exhibit 2-8. The results of this sensitivity analysis, presented in Exhibit 2-9, suggest that the project team's learning curve adjustments had only a minimal impact on the estimated costs incurred by EGUs as a result of the Amendments. In aggregate, these adjustments do not change the cost estimates by more than 4.6 percent. This small effect reflects the project team's methodology for capturing learning curve impacts. As outlined above, the cost equations supporting the EGU analysis reflect the costs associated with emission controls installed in 2004. Therefore, although we reduced the cost projections generated by IPM for FGD, SCR, and SNCR investments made after 2004, we increased the cost estimates for investments made prior to 2004.[65] Because these adjustments partially offset each other, the impact of our learning curve adjustments is minimal. In addition, because our results for 2001 reflect no costs incurred after 2004 (i.e., the vintage of the cost equations in IPM), our cost estimates for 2001 are higher when we make corrections for learning curve impacts, as shown in Exhibits 2-8 and 2-9.

[62] The compliance deadlines for the first phase of the Clean Air Interstate Rule are January 1, 2009 for NO_x and January 1, 2010 for SO_2. Similarly, the Clean Air Mercury Rule Phase 1 emissions cap of 38 tons per year goes into effect in 2010. The deadline for NOx SIP Call implementation was May 31, 2004 for all affected sources except those in Missouri and Georgia. The compliance deadline for sources in these two states was May 1, 2005.

[63] The compliance deadline for the second phase of the Clean Air Interstate Rule is January 1, 2015. In 2018, the mercury emissions cap established under the Clean Air Mercury Rule falls from 38 tons per year to 15 tons per year.

[64] With respect to the cost of NO_x control relative to SO_2 controls, the regulatory impact analysis for the Clean Air Interstate Rule indicates that the marginal cost of EGU NO_x abatement in 2010 under CAIR is $1,300 per ton, compared to just $700 per ton of SO_2 abated. U.S. EPA, *Regulatory Impact Analysis for the Final Clean Air Interstate Rule*, March 2005, EPA-452/R-05-002.

[65] As described above, we used the capital cost equations included in IPM to estimate the capital costs associated with utilities' FGD, SCR, and SNCR investments made between 1990 and the beginning of the IPM planning horizon because capital cost data for these investments are not readily available.

Exhibit 2-8. Annual Costs of the Clean Air Act Amendments for Electricity Generating Units in 2001, 2010, and 2020 (millions of year 1999$)

	2001	*2010*	*2020*
Capital Costs			
Scrubber retrofits	$239.4	$977.3	$1,635.4
Selective catalytic reduction retrofits	$46.3	$712.4	$871.2
Selective non-catalytic reduction retrofits	$2.6	$137.6	$137.9
Activated carbon injection retrofits	$0.0	$2.1	$175.6
Other capital costs	$129.6	$364.5	$290.2
Total Capital Costs	***$417.9***	***$2,193.8***	***$3,110.3***
Operation and Maintenance Costs			
Scrubber retrofits	$0[a]	$1,034.3	$1,830.9
Selective catalytic reduction retrofits	$0[a]	$183.3	$293.3
Selective non-catalytic reduction retrofits	$0[a]	$6.2	$8.2
Activated carbon injection retrofits	$0[a]	$12.6	$313.2
Fuel	$419.8	$483.0	$1,615.7
Other O&M	$316.5	$1,670.2	$1,739.1
Total O&M	*$736.3*	*$3,389.6*	*$5,800.4*
TOTAL	**$1,154.2**	**$5,583.4**	**$8,910.7**

Notes:

a. Because of the configuration of IPM, we were only able to separate emission control device O&M costs from other O&M costs for those devices installed during IPM's planning horizon (i.e., 2007-2030 for the 2010/2020 analysis and 2001 for the 2001 analysis). O&M costs for controls installed prior to the IPM planning horizon are included in the Other O&M category. Therefore, because we did not allow IPM to add retrofits to individual units for the 2001 model run, we were not able to separate any O&M costs for individual emission control devices from other O&M costs for 2001.

Exhibit 2-9. Annual Costs of the Clean Air Act Amendments for Electricity Generating Units in 2001, 2010, and 2020: No Learning Curve Cost Adjustments (millions of year 1999$)

	2001	*2010*	*2020*
Capital Costs			
Scrubber retrofits	$233.4	$987.4	$1,682.6
Selective catalytic reduction retrofits	$40.2	$719.2	$896.9
Selective non-catalytic reduction retrofits	$2.6	$138.9	$139.3
Activated carbon injection retrofits	$0.0	$2.1	$175.6
Other capital costs	$129.6	$364.5	$290.2
Total Capital Costs	***$405.9***	***$2,212.1***	***$3,184.5***
Operation and Maintenance Costs			
Scrubber retrofits	$0[a]	$1,121.8	$2,112.5
Selective catalytic reduction retrofits	$0[a]	$212.5	$356.5
Selective non-catalytic reduction retrofits	$0[a]	$6.2	$8.2
Activated carbon injection retrofits	$0[a]	$12.6	$313.2
Fuel	$419.8	$483.0	$1,615.7
Other O&M	$314.7	$1,673.0	$1,750.5
Total O&M	*$734.5*	*$3,509.1*	*$6,156.6*
TOTAL	**$1,140.4**	**$5,721.2**	**$9,341.2**

Notes:

a. Because of the configuration of IPM, we were only able to separate emission control device O&M costs from other O&M costs for those devices installed during IPM's planning horizon (i.e., 2007-2030 for the 2010/2020 analysis and 2001 for the 2001 analysis). O&M costs for controls installed prior to the IPM planning horizon are included in the Other O&M category. Therefore, because we did not allow IPM to add retrofits to individual units for the 2001 model run, we were not able to separate any O&M costs for individual emission control devices from other O&M costs for 2001.

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CHAPTER 3 - ON-ROAD MOTOR VEHICLES

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. Motor vehicle-related controls result from Title I ozone and CO-related nonattainment provisions, as well as Title II, which contains provisions related to mobile sources. 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 - while fuels requirements take effect across the entire fleet as soon as they are fully phased-in. The impact of new engine 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 costs 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.

This chapter summarizes the costs of each of these motor vehicle measures. We first provide a general summary of methods, then present our detailed methods and results for developing direct cost estimates for each of the major on-road motor vehicle provisions of the CAAA of 1990. We conclude with a summary of the overall motor vehicle provision costs.

Summary of Approach

Future year motor vehicle program costs are estimated for each of the control assumptions modeled in the emission projections analysis.[66] Motor vehicle control costs are calculated based on one of the following algorithms:

Cost per new vehicle -
Cost = projected vehicle sales * production cost ($/new vehicle)

Cost per registered vehicle -
Cost = projected vehicle registrations * cost per vehicle ($/vehicle)

Cost per gallon of fuel consumed -
Cost = projected fuel consumption (gallons) * cost per mile (cents/gallon)

Projected vehicle sales, registration, and gallons of fuel consumed are calculated from the VMT projections used in the Section 812 emissions analysis and projected motor vehicle data from the *Annual Energy Outlook 2005* (DOE, 2005). The AEO contains information on transportation sector energy use by mode and type (i.e., vehicle type), vehicle sales by technology type, vehicle stock (registration) by technology type, and fuel economy by technology type. These *Annual Energy Outlook 2005* supplemental data are used as a consistent data source to convert the Section 812 VMT projections (that

[66] See "Emission Projections for the Clean Air Act Second Section 812 Prospective Analysis, Draft Report" for a discussion of the emission projection methodology and the control assumptions (Pechan and IEC, 2006).

were also based on AEO2005 projected VMT) to new vehicle sales, registered vehicles, and fuel consumption projections.[67]

Unit control cost inputs were developed for all the control options modeled in the Section 812 emissions analysis. The cost data file indicates the unit cost (cents/gallon, $/registered vehicle, $/new vehicle sale) for each of the motor vehicle controls, with separate unit costs calculated for each vehicle type (e.g., light-duty gasoline vehicle (LDGV), light-duty gasoline truck 1 (LDGT1), LDGT2). These unit cost estimates of individual CAAA provisions were then multiplied by the AEO-based projections of fuel consumption, registrations, and new vehicle sales to estimate the national costs of onroad vehicle compliance with Title I and Title II in each analysis year (2000, 2010, and 2020). Since some control programs, such as vehicle inspection and maintenance (I/M) programs, or reformulated gasoline, apply only in specified counties, all cost calculations were made at the county/SCC level of detail.

To account for the cost-reducing effect of learning curve impacts, we applied a learning rate of 13 percent to the variable costs associated with fitting motor vehicles with pollution control devices required as a result of the 1990 Amendments.[68] This value is the average of two estimates we identified in the learning curve literature. Baloff (1971) suggests that the number of labor hours per unit of output for automobile assembly declines by 16 percent with each doubling of cumulative production.[69] Similarly, Epple et al. (1991) estimate that per unit labor requirements for truck manufacturing decline by 10 percent with each doubling of cumulative truck production.[70] Although these labor-hour learning rates do not necessarily correspond to the learning rates for other variable costs in automobile and truck production, they likely represent an analog of learning for variable costs because labor makes up a significant portion of these costs. In addition, to the extent that installing emission controls is similar to installing other motor vehicle components, we believe the results of the Baloff and Epple et al. studies are applicable to motor vehicle pollution controls. Absent learning rate estimates specific to these devices, the Baloff and Epple et al. results represent the best information available on the learning effects associated with motor vehicle pollution controls. To minimize the potential for overestimating the cost reductions related to learning effects, we limited our learning curve cost adjustments to the first two doublings of cumulative production, consistent with EPA practice in many regulatory impact analyses for rules affecting on-road sources.

As indicated above, our learning curve adjustments apply only to the variable costs associated with installing emission controls on motor vehicles as a result of the Amendments. We do not make learning curve adjustments for any incremental operating costs that vehicle purchasers may incur due to these controls. In addition, although vehicle manufacturers (and their suppliers) incur significant fixed costs associated with research and development, emission certification, and other activities to ensure that their vehicles are CAAA compliant, we do not believe that learning would significantly reduce the costs

[67] To estimate VMT in 2010 and 2020, the project team applied the VMT growth rate implied by the AEO 2005 VMT projections to 2000 VMT estimates previously developed by EPA. The project team then estimated vehicle sales for 2010 and 2020 by multiplying these VMT projections by the ratio of VMT (by vehicle type) to sales (by vehicle type), as derived from AEO 2005's VMT and vehicle sales projections.

[68] This 13 percent learning rate differs from the 20 percent learning rate used in several recent regulatory impact analyses (RIAs) for rules affecting on-road sources. In those cases where we relied on unit cost data from these RIAs to develop the cost estimates presented in this chapter, we backed the application of the 20 percent learning rate out of these unit cost estimates before applying the 13 percent learning rate.

[69] Baloff (1971) as cited in Auerswald, Philip, Stuart Kauffman, José Lobo, and Karl Shell. "The production recipes approach to modeling technological innovation: An application to learning by doing," Journal of Economic Dynamics & Control, Vol. 24, 2000, 389-450.

[70] Epple, *et al.* (1991) as cited in Auerswald, *et al.*, *op. cit.*

of these activities. We also do not attempt to capture any learning curve effects that might reduce the costs associated with CAAA-related fuel requirements or inspection and maintenance programs.

To estimate the cumulative production of on-road vehicles during the 1990-2020, we used sales information from two sources. For the 2000-2020 period, we used sales estimates derived from the section 812 VMT projections, as outlined above. For 1990 through 1999, we used sales data, by vehicle type, from the Oak Ridge National Laboratory's (ORNL's) *Transportation Energy Data Book*.[71] Although we would ideally use sales estimates derived from a single source rather than two sources, the combined time series derived from the project team's 2000-2020 sales estimates and the ORNL estimates for 1990-1999 serves as a reasonable basis for assessing learning curve impacts for on-road sources.

Major Programs And Analysis Methods

Exhibit 3-1 lists the mobile source control programs and provisions modeled in this analysis. The derivation of the unit costs for each of these programs are discussed individually in this section.

1. Light-Duty Vehicle Emission Standards

a. Tier 1 Certification Standards and Evaporative Controls

The 1990 CAAA specified Tier 1 emission standards for light-duty vehicles and light-duty trucks. EPA promulgated these standards in 1991, and implementation of the new standards began being phased in with the 1994 model year. The Tier 1 tailpipe standards include NO_x, VOC, and CO limits for LDGVs and LDGTs. NO_x standards are also specified for heavy-duty gasoline and diesel vehicles.

Costs for tailpipe standards and evaporative controls are calculated based on a per-vehicle production cost applied to projected sales. Costs for tailpipe standards are delineated by pollutant, as shown in Exhibit 3-2. Based on EPA's 1991 analysis of the Tier 1 Standards, we estimate that the Tier 1 HC controls cost approximately $36.23 per vehicle and that the Tier 1 NO_x controls cost approximately $113.37 per vehicle (56FR25724, 1991).[72] The initial cost increase is multiplied by projected sales to estimate the annual cost for each projection year.

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[71] U.S. Department of Energy, Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 25*, 2006.

[72] These and all of the other unit cost values presented in this chapter reflect the learning curve cost adjustments we describe above. In addition, they are expressed in year 1999 dollars. Because most of the cost studies used as sources in this chapter do not express costs in year 1999 dollars and do not employ learning curve assumptions consistent with ours, the unit cost values in these studies are often different than those presented in this chapter.

Exhibit 3-1. Applicability of Mobile Source Control Programs

Control Measure	Applicability
Phase II Reid Vapor Pressure (RVP) Limits	National (standard varies by region)
Tier 1 Tailpipe Standards (LDVs and LDTs)	National
Cold Temperature CO Standard	National
Onboard Diagnostic Systems	National
Tier 2 Tailpipe Standards	National
New Evaporative Emission Test Procedure	National
Onboard Vapor Recovery System	National
Heavy-Duty NO_x Standard 4.0 grams/brake horsepower-hour (g/bhp-hr), 2.0 g equivalent	National
Heavy-Duty Diesel Vehicle 2007 Emission Standards	National
Federal Reformulated Gasoline	Nine areas required to adopt this program under the CAA plus areas which have opted in to this program
California Reformulated Gasoline	State of California
Oxygenated Fuel	All CO nonattainment areas
California Reformulated Diesel	State of California
Diesel Fuel Sulfur Limits (1993)	49 States
Diesel Fuel Sulfur Limits (15 ppm)	National
Gasoline Fuel Sulfur Limits	National
Basic Inspection and Maintenance (I/M)	All moderate ozone nonattainment areas, moderate CO nonattainment areas, and areas with I/M in 1990
Low Enhanced I/M	All areas previously required to implement high enhanced I/M who are able to meet the 1990 CAA requirements for RFP and attainment without the more stringent high enhanced I/M program
High Enhanced I/M	Serious and above ozone nonattainment areas, in metropolitan areas in the OTR with populations above 100,000, and in serious CO nonattainment areas
National LEV	Nationally, except California (49 States)
California LEV	California
Clean Fuel Fleet Program	Atlanta, Metropolitan Washington, DC, Chicago-Gary-Lake County, Milwaukee-Racine, Denver-Boulder, Baton Rouge
Heavy-Duty Diesel Defeat Device Settlements	National

Exhibit 3-2. Production Costs for Tailpipe Standards (in 1999 Dollars)

Control	Cost
VOC Tailpipe Standards	\$36.23 LDGV
	\$32.66 LDGT1
	\$10.90 LDGT2
NO_x Tailpipe Standards	\$113.37 LDGV
	\$78.02 LDGT1
	\$42.18 LDGT2
	\$14.90 heavy-duty gasoline vehicle (HDGV)
	\$72.63 heavy-duty diesel vehicle (HDDV) (4.0 g/bhp-hr)
Cold Temperature CO Standards	\$17.94 LDGV (1999 dollars)
	\$30.01 LDGT1 (1999 dollars)
	\$45.96 LDGT2 (1999 dollars)

NOTES: The cost of \$32.66 for VOC tailpipe standards for LDGT1 is based on an incremental cost for LDGT1a and LDGT1b weighted by the sales fraction of each (57 percent LDGT1a, 43 percent LDGT1b).

Evaporative VOC emissions have been reduced in gasoline-powered cars as new Federal (and California) evaporative test procedures were implemented. Based on EPA's regulatory impact analysis for these procedures, we expect the initial retail price equivalent increase of about \$8.45 per vehicle to be largely offset by fuel savings. EPA estimated these fuel savings from evaporative VOC emissions control at a cost of \$1.11 per gallon (EPA, 1993e).[73] Therefore, the net cost to the consumer is estimated to be -\$1.51 for light-duty vehicles (LDVs), \$6.03 for light-duty trucks (LDTs), and -\$17.04 for heavy-duty vehicles (HDVs) (EPA, 1993e). Cost components are shown in Exhibit 3-3. Annual costs are estimated using the net vehicle cost and the estimated sales in the projection year.

Exhibit 3-3. Evaporative Emissions Control Cost Summary (in 1999 Dollars)

	LDV	LDT	HDV
Consumer Cost	\$8.45	\$11.57	\$9.54
Net Fuel Savings	\$9.97	\$5.54	\$26.58
Net Cost	-\$1.51	\$6.03	-\$17.04

b. Cold Temperature CO Standard

Section 202 of the CAA requires EPA to set cold temperature (20^{o}F) CO emission standards for LDVs and LDTs. The 1992 final rule established emission standards at 20^{o}F, applicable for a 50,000 mile useful life of: 10.0 grams per mile (g/mi) for LDV; 10.0 g/mi for LDTs with a 3,750 pounds or less loaded vehicle weight (LVW); and 12.5 g/mi for LDTs with a LVW greater than 3,750 pounds (57FR31888, 1992). These standards were phased-in over a period of three years, with 100 percent of 1996 sales required to meet these new standards.

[73] The fuel value presented in the RIA is \$1.00 per gallon expressed in year 1993 dollars. The \$1.11 per gallon estimate above reflects the \$1.00 estimate expressed in year 1999 dollars, based on the GDP Implicit Price Deflator.

The cost of the cold temperature CO standard to the consumer includes the cost to the manufacturer, plus the manufacturer's and dealer's overheads and profits, plus any increase or decrease in maintenance and fuel costs. Maintenance costs should not change as a result of the proposed rule, and fuel costs are expected to decrease (EPA, 1989). Based on EPA's regulatory impact analysis for the cold temperature CO standards, we estimate that the standards increase retail prices paid by consumers by $17.94 for LDVs, $30.01 for LDT1s, and $45.96 for LDT2s. While associated fuel economy improvements are expected to offset these initial cost increases, those benefits have not been included in this analysis.[74]

c. Onboard Vapor Recovery

Section 202 of the CAAA required EPA to regulate vehicle refueling emissions by requiring onboard emission control systems that would provide a minimum evaporative emission capture efficiency of 95 percent. In 1994, EPA issued a final rule implementing the control of vehicle refueling emissions through the use of vehicle-based systems. It applies to LDVs and LDTs. For LDVs, the requirements began in model year 1998, and phased-in over three model years. In the 1998 model year, 40 percent of each manufacturer's LDVs were required to meet the requirements. This increased to 80 percent in the 1999 model year, and rose to 100 percent in model years 2000 and later.

This requirement also applies to LDTs. For LDTs with a gross vehicle weight (GVW) rating of 0-6,000 pounds, the requirement began in model year 2001, and phased-in over three model years at the same rate as applied to LDVs. For LDTs with a GVW rating of 6,001-8,500 pounds, the requirement began with model year 2004, and phased-in over three model years at the same rate as LDVs. The rule does not apply to HDVs.

The EPA RIA for onboard vapor recovery includes cost estimates by vehicle type expressed in two terms: (1) expected increase in vehicle price (retail price equivalent), and (2) an average lifetime operating cost (net present value) (EPA, 1993f). Per vehicle costs for onboard vapor recovery systems used in this analysis are shown in Exhibit 3-4.

Exhibit 3-4. Per Vehicle Costs for Onboard Vapor Recovery Systems (in 1999 Dollars)

	2000			2010 and 2020		
	LDV	LDT1	LDT2	LDV	LDT1	LDT2
Increase in Vehicle Price (RPE)	$6.29	$7.34	$7.34	$6.13	$7.15	$7.15
Average Lifetime Operating Cost (NPV)	-$2.18	-$3.40	-$3.40	-$2.18	-$3.40	-$3.40
Total Cost	$4.12	$3.94	$3.94	$3.95	$3.75	$3.75

d. Onboard Diagnostic Systems

The onboard diagnostic (OBD) regulations (section 207 of Title II) require vehicle manufacturers to install diagnostic systems on LDVs and LDTs starting with the 1994 model year. From an analysis standpoint, OBD provides emission benefits in much the same way as emission inspection programs.

[74] The Project Team is currently working on adapting the measures of fuel savings in the RIA to correspond with the fuel cost, pre-tax adjustment, and net present value calculation assumptions (including a 5 percent discount rate).

RIA-presented OBD costs were estimated largely from data collected from motor vehicle manufacturers. Based on the results of the RIA, we estimate hardware costs of approximately $55 per LDV (EPA, 1993d). Given the advances in software and computing technology since the completion of the RIA, however, this value is somewhat uncertain.

e. California Low Emission Vehicle Program

In September 1990, the California Air Resources Board (CARB) approved their original low-emission vehicle (LEV) and Clean Fuels regulations. These regulations established four new classes of light and medium-duty vehicles with increasingly stringent emission levels: transitional low emission vehicle (TLEV), LEV, ultra-low emission vehicle (ULEV), and zero-emission vehicle (ZEV). The regulations also established a decreasing fleet average standard for emissions of nonmethane organic gas (NMOG). Auto manufacturers can meet the fleet average NMOG standard using any combination of TLEVs, LEVs, ULEVs, and ZEVs they choose. However, CARB also included a ZEV requirement as part of the LEV regulations. ZEVs are defined as vehicles with no direct exhaust or evaporative emissions.

Various groups have estimated the costs of producing vehicles that meet the various LEV category standards. Differences between low and high estimates are about a factor of 10. While CARB's cost estimates are the lowest, they are also the most fully documented so they are used here to develop cost per ton estimates (CARB, 1996). Adjusting the CARB estimates for learning curve impacts, we estimate per vehicle costs of $66 for TLEVs, $104 for LEVs, and $123 for ULEVs. (These costs are relative to a Federal Tier 1 vehicle). CARB also estimates costs of approximately $5,214 per vehicle for ZEVs. Because ZEVs may include a variety of different technologies (e.g., fuel cells, electric motors, etc.), we do not apply learning curve adjustments to this estimate.

Although the overall LEV program was widely considered successful at reducing vehicle emissions and promoting advanced emission control technologies, the ZEV experiment has fallen short of expectations (NRC, 2006). This requirement was originally premised on the availability of electric vehicles by model year 1998. The ARB has revised its original ZEV mandate four times, resulting in a much different requirement now that no longer emphasizes electric vehicles. The ARB originally thought in 1990 that, by 2000, electric vehicles would be comparable in cost to conventional vehicles plus an estimated $1,350 per vehicle cost for the batteries (CARB, 1990). In 1994, CARB increased its estimate of the additional cost of an electric vehicle to $5,000-10,000 more than a conventional gasoline-fueled vehicle (CARB, 1994). In its 2000 review of the ZEV mandate, CARB staff estimated that the incremental cost of a freeway-capable ZEV would be approximately $20,000 more than a conventional vehicle (CARB, 2000). Because of these high costs, CARB currently assumes that vehicle manufacturers will produce large numbers of near zero emission vehicles to satisfy the alternative compliance option to meet their ZEV requirements and that few zero emission vehicles will be sold in California in the immediate future. Due to resource constraints, the Project Team was unable to find data specific to the incremental cost of near zero emission vehicles. Therefore, we use CARB's original estimate of $5,214 per vehicle for ZEVs, as stated above, as a proxy for these costs. The Project Team will consult other data sources for a more appropriate unit cost estimate before publishing the final Second Prospective cost report.

f. National Low Emission Vehicle Program

Based on a series of agreements between EPA, the northeastern States, and the auto manufacturers, EPA's National LEV program went into effect in 1998. As a result of these agreements, new cars and light-duty trucks sold in the northeastern states starting in model year 1999 and nationally beginning in model year 2001 met emission limits more stringent than the Tier 1 emission limits and more stringent than EPA could mandate prior to 2004.

CARB estimates of LEV program costs per vehicle (see above) are used as the basis for this analysis (CARB, 1996) because the National LEV requirements are comparable to those in California. The incremental costs of the program apply to both light-duty gasoline vehicles (LDGVs) as well as light-duty gasoline trucks (LDGTs); however, unit cost estimates for LDGVs were applied to both categories. Because light-duty cars and trucks use many of the same technologies, our results would likely be similar if separate unit cost estimates for LDGTs were available.

g. Tier 2 Vehicle Emission Standards

The 1990 CAAA required EPA to consider the need, feasibility, and cost-effectiveness of tailpipe emission standards stronger than the Tier 1 standards with implementation beginning in the 2004 model year. EPA determined that tighter tailpipe standards were necessary to reach the air quality goals set out in the CAAA. However, along with tighter tailpipe controls, EPA also indicated a need for significantly lower levels of sulfur in gasoline as high sulfur levels would impede the performance of catalytic converters that would be needed to meet the new emission standards. The Tier 2 Vehicle and Gasoline Sulfur regulations were finalized in 1999. This program requires all passenger cars, light trucks, and medium-duty passenger vehicles (which includes sport-utility-vehicles and passenger vans from 8,500 to 10,000 pounds gross vehicle weight rating) to meet an average emission standard of 0.07 grams of NOx per mile, beginning in the 2004 model year. The phase-in of the final emission standards is to be completed with the 2009 model year. (The fuel portion of this regulation is costed separately, as described in the fuels section of this chapter.)

EPA's Tier 2 RIA shows costs to consumers of the Tier 2 emission standards including potential increases in vehicle purchase price and vehicle operating costs (EPA, 1999). All Tier 2 costs are incremental to the costs of meeting the NLEV emission standards. For the initial cost, or purchase price increase, EPA anticipates that manufacturers would pass along their incremental costs for Tier 2 vehicles, including a mark-up for overhead and profit, to vehicle purchasers. To account for manufacturer overhead and profit, manufacturer incremental variable costs are multiplied by a retail price equivalent (RPE) factor. The RPE factor, 1.26, is consistent with that applied for other emission standard cost analyses. Exhibit 3-5 presents the estimated increases in Tier 2 vehicle costs. The estimated costs shown in this table include the costs of needed evaporative system improvements (incremental to onboard vapor recovery systems) as well as the improved exhaust emissions control system. Similar to the other cost estimates presented in this chapter, these estimates show the expected effects of learning curves with increased cumulative production of affected vehicles.

Exhibit 3-5. Incremental Per Vehicle Costs to Consumers for Tier 2 Vehicles (in 1999 Dollars)

Production Year	LDV	LDT1	LDT2	LDT3	LDT4/MDPV
1st year	$82.43	$73.80	$129.54	$248.92	$261.57
2010 and 2020, learning curve applied and fixed costs expired	$45.72	$41.12	$83.47	$173.56	$181.95

NOTE: MDPV = medium-duty passenger vehicle.

SOURCE: EPA, 1999.

2. Heavy-Duty Vehicle Emission Standards

a. Heavy-Duty Vehicle 2 grams/brake horsepower-hour (g/bhp-hr) Equivalent NO_x Standard

In September 1997, EPA issued a final rule for a new combined emission standard for HC and NO_x from heavy-duty engines designed for HDTs and buses. Under this new mandate, manufacturers have the option of certifying their engines to one of two standards:

2.4 g/bhp-hr nonmethane hydrocarbons (NMHC) + NO_x
or
2.5 g/bhp-hr NMHC + NO_x
with a limit of 0.5 g/bhp-hr on NMHC

EPA estimates of the cost of complying with 2004 model year emission standards begin with an estimate of the baseline package of emission control technology for meeting 1998 model year standards (EPA, 1997f). The baseline control technologies projected for engines meeting 1998 emission standards include technologies that contribute directly to lower NO_x emissions and a variety of engine improvements with only secondary benefits for NO_x control. The baseline scenario includes full utilization of electronic controls and unit injectors.

EPA's analysis anticipated a combination of primary technology upgrades for the 2004 model year. Achieving very low NO_x emissions was expected to require basic research on reducing in-cylinder NO_x and HC. Modifications to basic engine design features can improve intake air characteristics and distribution during combustion. Manufacturers were also expected to use upgraded electronics and advanced fuel injection techniques and hardware to modify various fuel injection parameters, including injection pressure, further rate shaping, and some split injection.

Exhibit 3-6 shows the derivation of the unit costs for the HDV 2.0 gram equivalent NO_x emission standards that are used in this Section 812 Prospective Analysis to estimate 2010 costs. The EPA regulatory analysis for this standard evaluates costs for the appropriate subcategories of heavy-duty diesel and gasoline vehicles, as control technologies and costs differ somewhat among light, medium, and heavy-duty trucks. The 1994 model year sales of different size classes of diesel trucks are used to establish sales fractions, which are expected to be representative of future year sales as well. The year 2009 per vehicle cost increases for light, medium, and HDVs are multiplied by these sales fractions to compute a sales-weighted per vehicle cost increase. The resulting incremental NPV cost increases are $175 for HDDVs. HDGVs are not affected by these new emission standards.

Exhibit 3-6. Estimated Per Vehicle Costs of 2 Gram Equivalent Heavy-Duty Vehicle Emission Standard

Vehicle Type	1995 MY Sales	Sales Fractions	2010 and 2020 Per Vehicle Cost Increase (1999$)	Weighted Per Vehicle Cost Increase (1999$)
Light Heavy-Duty Diesel	280,000	41%	$137	
Medium Heavy-Duty Diesel	140,000	21%	$171	$175
Heavy Heavy-Duty Diesel	220,000	33%	$226	
Urban Buses	35,000	5%	$179	
Total	**675,000**	**100%**		

SOURCE: EPA, 1997f.

b. Heavy-Duty Vehicle 2007 Emission Standards

In January 2001, EPA finalized its 2007 Heavy-Duty Highway Rule. This rule sets new emission standards for heavy-duty highway engines as well as requiring significant reductions to the sulfur content of diesel fuel used in highway vehicles. The regulation sets the emission standards for new heavy-duty highway vehicles to 0.01 grams per brake-horsepower-hour (g/bhp-hr) for PM, 0.20 g/bhp-hr for NOx, and 0.14 g/bhp-hr for NMHC. These emission standards are to be phased in starting with the 2007 model year, with phase-in to be completed with the 2010 model year. These standards apply to both diesel and gasoline highway engines. (The costing of the sulfur requirements for diesel fuel is discussed separately in the fuels section of this chapter.)

The estimated per vehicle costs for the 2007 HDDV emission standards are based on the costs estimated by EPA for the RIA. The EPA analysis divides the affected heavy-duty vehicles into four service types, and estimates per vehicle costs using this breakdown of heavy-duty vehicles into service types, as shown in Exhibit 3-7.

Exhibit 3-7. Service Classes of Heavy-Duty Vehicles

Service Class	Vehicle Class	Gross Vehicle Weight Rating (lbs)
Light	2B-5	8,500-19,500
Medium	6-7	19,501-33,000
Heavy	8	33,001+
Urban Bus	--	--

Control cost estimates are developed for three primary elements:

1. Variable costs – including incremental hardware costs, assembly costs, and associated markups.
2. Fixed costs – these include tooling, research and development, and certification. The RIA for the Standards assumes that fixed costs such as research and development are amortized over the first five years of compliance.
3. Operating costs.

These cost estimates are summarized in Exhibit 3-8.

i. Technology/Hardware Costs for Diesel Vehicles and Engines

The EPA RIA estimates of hardware costs to meet the 2007 HDDV emission standards were based on EPA's belief that a small set of technologies integrated into a single emission control system would be the primary changes manufacturers would make to meet the 2007 model year standards. This integrated system was expected to include elements that include a NO_x adsorber catalyst, a catalyzed diesel particulate filter, a diesel oxidation catalyst, and 15 ppm sulfur diesel fuel to enable the emission control technologies to meet the required emission limits. In order to comply with the requirement to eliminate crankcase emissions from all heavy-duty diesel engines, EPA projected the introduction of closed crankcase filtration systems. Lean NO_x catalysts and compact SCR systems were not considered in the EPA analysis because they were not projected to be part of 2007 model year technology changes.

ii. Operating Costs

EPA's RIA for the HDDV emission standards evaluates operating cost changes associated with new standards and technologies introduced beginning in 2007. The operating cost components that EPA identified in its RIA included the following:

1. Diesel fuel cost increases.
2. Periodic replacement of a paper filter element.
3. Reduced maintenance costs.
4. Fuel economy changes.

The EPA RIA handles diesel fuel cost increases as a net present value cost over a vehicle lifetime. This section 812 analysis accounts for the cost of reducing the sulfur content of diesel fuel to 15 ppm as if the fuel regulation was separate from the emission standard, and the estimated cost is based on the cents per gallon retail price equivalent cost increase. This fuel cost is addressed in a separate section of this chapter.

Exhibit 3-8. Summary of Near and Long Term Cost Estimates of HDE 2007 Emission Standards

Light Heavy Duty Diesel Vehicles
(1999 Dollars per Engine)

Cost Element	*2007 (Compliance Deadline)*	*2010*	*2020*
Fixed Cost	$128	$128	$0
Variable Cost	$1,858	$1,406	$1,406
Operating Cost	$86	$86	$81
TOTAL COST PER VEHICLE	$2,072	$1,620	$1,487

Medium Heavy Duty Diesel Vehicles
(1999 Dollars per Engine)

Cost Element	*2007 (Compliance Deadline)*	*2010*	*2020*
Fixed Cost	$329	$329	$0
Variable Cost	$2,235	$1,692	$1,692
Operating Cost	$115	$115	$104
TOTAL COST PER VEHICLE	$2,679	$2,136	$1,796

Heavy Heavy Duty Diesel Vehicles
(1999 Dollars per Engine)

Cost Element	*2007 (Compliance Deadline)*	*2010*	*2020*
Fixed Cost	$280	$280	$0
Variable Cost	$2,946	$2,230	$2,230
Operating Cost	$375	$375	$329
TOTAL COST PER VEHICLE	$3,601	$2,885	$2,559

Urban Buses (Diesel)
(1999 Dollars per Engine)

Cost Element	*2007 (Compliance Deadline)*	*2010*	*2020*
Fixed Cost	$280	$280	$0
Variable Cost	$2,608	$1,974	$1,974
Operating Cost	$205	$205	$190
TOTAL COST PER VEHICLE	$3,093	$2,459	$2,164

EPA estimated that there would be no fuel economy changes in the vehicles affected by the HDDV emission standard, so the estimated cost of fuel economy changes was zero. Therefore, this operating cost analysis focuses on the cost of periodic replacement of a paper filter element, and reduced maintenance costs.

An integral part of the system expected to be used to meet the HDDV emission standards is a paper filter designed to capture oil mist in the blow-by gases, coalesce this oil, and return this filtered oil to the oil sump. These filters are expected to require replacement on a fixed interval of 30,000 miles. The cost of these filters in 2007 has been estimated to be $10, $12, and $15 for light, medium, and heavy heavy-duty vehicles, respectively.

There are also expected to be maintenance costs for catalyzed diesel particulate filters (CDPFs). EPA estimated that for CDPF-equipped vehicles in 2007 and beyond, the maintenance interval will be 100,000 miles for light heavy-duty vehicles and 150,000 miles for medium and heavy heavy-duty vehicles. The cost of this service is the labor cost to remove and clean the filter. This removal and reinstallation should take one hour at $65 per hour.

Eliminating the need to replace the exhaust gas recirculation (EGR) valve on heavy heavy-duty diesel engines represents a cost savings to vehicles built with EGR systems of $115 in the year of the engine rebuild. These savings only apply to vehicles built after 2004, because vehicles built prior to this will have operated primarily on high sulfur diesel fuel. Savings for light and medium heavy-duty vehicles are not estimated because engines in these vehicle classes are less likely to be rebuilt. (For heavy engines, 95 percent reaching 560,000 miles are rebuilt – 72 percent of heavy heavy-duty vehicles reach 560,000 miles (year 7 of their life).) The cost savings of $115 in the year of the engine rebuild is modeled as a $51 savings in net present value in the year of the vehicle sale (EPA, 2000).

Other maintenance savings identified by EPA in the RIA are included in this analysis as a cost savings element associated with the low sulfur diesel and are discussed in that section of this chapter.

iii. Costs for Heavy-Duty Gasoline Vehicles

The 2007 Heavy Duty Highway Rule also includes new emission standards for heavy-duty gasoline vehicles, to be implemented beginning with the 2008 model year. EPA estimated the cost of meeting these new standards as shown in Exhibit 3-9 (EPA, 2000):

Exhibit 3-9. Incremental Costs to Meet the Heavy-Duty Gasoline Emission Standards (in 1999 Dollars)

Cost Element	2008 (Compliance Deadline)	2010	2020
Technology/Hardware Costs	$184	$147	$139
Fixed Costs	$14	$14	$0[a]
Total Incremental Cost	$198	$161	$139

Notes:
a. The fixed costs of this rule are expected to be incurred only between 2008 and 2010. U.S. EPA, "Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements," December 2000, EPA420-R-00-026.

3. Fuels

a. Gasoline Volatility Limits

During the CAA debate, EPA adopted regulations to restrict the Reid vapor pressure (RVP) of gasoline during the ozone season. This was accomplished in two phases. Phase I of the RVP limits was implemented before 1990. Phase II RVP limits affected motor vehicle gasoline beginning in 1991, so its emission reductions and costs are accounted for in this analysis. The Phase II volatility program establishes limits for fuel RVP in all areas of the United States (56FR64704). The RVP limit depends on the State, month, and ozone classification. From May through September, gasoline sold in northern States (both attainment and nonattainment areas) is limited to 9.0 psi under the rule. In the warmer southern States, RVP is limited to 7.8 psi in nonattainment areas and 9.0 psi in attainment areas. The estimated cost of lowering the RVP in Class C areas from 10.5 to 9.0 is 0.225 cents per gallon in the five month ozone season (Wysor, 1988). This unit cost estimate is the same as that used in the First Prospective cost analysis.

b. Federal Reformulated Gasoline

Under the CAAA, nine cities with the worst smog pollution, classified as severe or extreme ozone nonattainment areas, were required to use reformulated gasoline (RFG). In addition, areas reclassified to severe or extreme nonattainment status are required to begin using reformulated gasoline. Moderate and marginal nonattainment areas are permitted to opt-in to the RFG program. Implementation of Phase I of the RFG program began in 1995 and implementation of Phase II began in 2000. EPA issued a final rule for Phase II RFG emission standards on February 16, 1994 (59FR7716, 1994).

Reformulated gasoline costs are based on an incremental refiner's cost increase and a monetized fuel economy disbenefit of 3.9 cents per gallon for Phase I and 5.1 cents per gallon for Phase II relative to conventional gasoline (EPA, 1993g). The Phase I benefits of RFG are primarily due to the lower oxygenate (with its effect on aromatic content) requirement of RFG and the reduction of fuel benzene content and will occur year round. Thus, the costs associated with the Phase I RFG benefits are applied year-round. Phase II reformulated gasoline costs are applied for five months of the year (May through September), because fuel modifications only occur in the summer, including a lower RVP requirement and a lower sulfur content requirement. The Phase II costs are applied in addition to the Phase I costs in RFG areas.

EPA estimated that RVP control down to 6.7 psi achieves virtually all of the VOC emission reductions that are achievable at less than $5,000 per incremental ton of VOC reduced. Sulfur can be reduced to a level of approximately 250 ppm at an incremental cost effectiveness of less than $5,000 per ton, gaining an additional 0.6 percent VOC reduction (on average) of 26.1 percent. RVP could also be further reduced to 6.5 psi, the lower limit for drivability purposes, to obtain an additional 1.1 percent reduction. It was also found that changes in fuel parameters other than RVP have only a small effect on VOC emissions, and can be very costly. Achieving another one percent (or less) reduction in VOC emissions would cost more than $10,000 per ton.

EPA evaluated the cost effectiveness of NO_x control using the same costs that were used in establishing the standard for VOC control. Analyses indicated that sulfur is the only fuel parameter that results in significant NO_x reductions at reasonable cost. Changes in fuel parameters other than sulfur have only a small effect on NO_x emissions, at significantly higher costs, with the possible exception of olefin control (which would increase VOC at the same time it reduced NO_x). A NO_x reduction of about 6.8 percent could be achieved with sulfur control down to about 138 ppm at a reasonable cost, whether compared on the basis of the last increment of reduction (5.8 percent to 6.8 percent NO_x) or the overall cost incremental to Phase I reformulated gasoline reductions.

The statute set the minimum Phase II standard for toxics reduction at 25 percent, although EPA has the authority to reduce this to no lower than 20 percent based on technological feasibility considering cost. EPA proposed both levels of reductions as options. However, it was found that for certain refiners with higher baseline levels of various parameters, EPA found that compliance with the VOC and NO_x standards will not automatically lead to compliance with a 25 percent toxics standard. EPA set the toxics standard at 20 percent in both VOC control regions because the cost effectiveness of toxics control beyond a 20 percent reduction is questionable.

c. California Reformulated Gasoline

The California Phase 1 reformulated gasoline standards were implemented January 1, 1992. Phase 1 specifications mandate limits on RVP, use of deposit control additives, and the elimination of leaded gasoline. Each of these directives results in higher per-gallon costs of fuels to consumers. The CARB has estimated the costs to the consumer of each of these three proposals (CARB, 1990).

The RVP reduction will cost 0.5 to 0.9 cents per gallon if it is assumed that costs are only incurred during the RVP season, and 0.35 to 0.6 cents per gallon if costs are spread throughout the year. Deposit control additives could range from 0.1 to 1.0 cent per gallon, with a typical cost range of 0.3 to 0.5 cents per gallon. The elimination of lead is estimated to cost 0 to 0.4 cents per gallon.

Based on the CARB documentation, the total cost of California Phase 1 reformulated gasoline is estimated to be no greater than 1.5 cents per gallon. This is based on summing the maximum cost for RVP incurred annually (0.6 cents per gallon), the maximum cost for the typical range of deposit control additives (0.5 cents), and the maximum cost for lead elimination (0.4 cents). There is no indication that additional costs would be incurred due to a fuel economy penalty.

California has also adopted regulations for Phase 2 reformulated gasoline (CARB, 1991); Phase 2 costs are significantly higher than those for the Phase 1 regulations that took effect in 1992. Phase 2 represents an attempt to generate maximum reductions in criteria and toxic pollutants, and in the mass and reactivity of emissions from gasoline fueled vehicles. Phase 2 gasoline must meet specified standards for sulfur content, benzene content, aromatic hydrocarbon content, olefin content, RVP, oxygen content, 90 percent distillation temperature (T90), and 50 percent distillation temperature (T50). Phase 2 standards began in California on January 1, 1996.

CARB estimates that Phase 2 California reformulated gasoline will cost refineries an additional 5 to 15 cents per gallon to produce (CARB, 1991). This is an estimate of the increase in after-tax expenses for a refiner who makes the "average gallon" of reformulated gasoline. An average value of 10 cents per gallon was used to estimate the cost of this control option. Costing for California reformulated gasoline is divided evenly between VOC and NO_x. California reformulated gasoline costs are applied throughout the year. A 2.3 cents per gallon fuel economy penalty is also applied when estimating Phase II California reformulated gasoline costs. This fuel economy penalty was based on a $1.14 per gallon fuel price—the average retail price of unleaded regular gasoline in California from the first quarter of 1990 through the first quarter of 1991 (CARB, 1991).

d. Oxygenated Fuels

Oxygenated fuel costs are based on an incremental cost of 3.8 cents per gallon (EPA, 1993g). This was converted to a cost per mile based on the projected fuel economy. Oxygenated fuel costs are attributed to CO and are calculated based on the number of months in which oxygenated fuels are used in the area. Oxygenated fuel benefits and costs are applied in all CO nonattainment areas, during the months in which it is required.

e. California Reformulated Diesel

California's vehicular diesel fuel regulation established a 500 ppm sulfur limit and required a reduction of the aromatic content of the fuel from 30 to 10 percent. Small refineries may produce fuels with higher aromatic contents (up to 20 percent) if equivalent emissions can be demonstrated through engine testing.

Reformulated diesel costing is based on an incremental per gallon increase of 6 cents (Green, 1994). This cost is converted to a cost per mile for each diesel-fueled vehicle, based on the projected fuel economy.

f. Diesel Fuel Sulfur Limits

The CAAA, in Section 217, required that effective October 1, 1993, motor vehicle diesel fuel would be limited to a sulfur concentration of 0.05 percent (by weight) and a cetane index minimum of 40. The incremental cost of low sulfur diesel fuel meeting these restrictions relative to conventional diesel fuel, is estimated by Bonner & Moore to be 1.8 to 2.3 cents per gallon (EPA, 1990). An average value of 2.1 cents per gallon is used in this analysis. No fuel economy penalty is applied for low sulfur diesel fuel because the energy content is estimated to be less than one percent lower than that of conventional fuel.

g. Tier 2 Gasoline Sulfur Limits

The Tier 2 gasoline sulfur control program required that most refiners and importers meet a corporate average gasoline sulfur standard of 120 ppm and a cap of 300 ppm beginning in 2004. In 2006, the cap was reduced to 80 ppm and most individual refineries were required to produce gasoline averaging no more than 30 ppm sulfur.

Estimated Per Gallon Cost of Desulfuring Gasoline to 30 ppm

Year	Cost in Cents per Gallon
2010	1.70
2020	1.30

NOTE: 7 percent return on investment, before taxes, 1997 dollars.

EPA estimated the per-gallon cost by Petroleum Administration for Defense District (PADD) based on an average refinery for each PADD using different amortization premises. In Exhibit 3-10, costs are shown for amortizing capital at a 7 percent rate of return on investment (ROI) before taxes, which is to represent the cost to society.[75] The range of costs presented in Exhibit 3-10 shows how varying the ROI before taxes from 6 to 10 percent affects the per-gallon cost estimates. This table presents costs in 2008 after program costs have stabilized.

Exhibit 3-10. Post Phase-in Cost (Year 2008) of Desulfurizing Gasoline to 30 ppm Based on Different Capital Amortization Rates

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	National Average
Societal Cost (7% ROI before Taxes)	2.00	1.65	1.52	2.32	2.63	1.70
Capital Payback (6% ROI, after Taxes)	2.04	1.69	1.54	2.41	2.67	1.73
Capital Payback (10% ROI, after Taxes)	2.22	1.85	1.65	2.76	2.87	1.87

h. Diesel Sulfur Standards

As discussed above, the 2007 Heavy-Duty Highway Rule limits the sulfur content of highway diesel fuel sold beginning in 2006. The diesel sulfur limit specified by this rule is 15 ppm. The total cost of 15 ppm sulfur diesel is the sum of refinery desulfurization costs, addition of a lubricity additive, and increases in distribution costs. Refinery desulfurization and distribution costs average 3.3 cents per gallon and 1.1 cents per gallon, respectively, during the initial years of the program. Lubricity additives average approximately 0.2 cents per gallon. Thus, EPA estimates the total cost of diesel fuel meeting the 15 ppm cap to be 4.5 cents per gallon during the initial years of the program. This cost will increase to 5 cents per gallon after 2010.

Low sulfur diesel fuel yields benefits in the form of reduced sulfur inhibited corrosion of vehicle components and slower acidification of engine lubricating oil, leading to longer maintenance intervals and lower maintenance costs. These benefits will apply to new vehicles and to the existing heavy-duty vehicle fleet beginning in 2006 when the fuel was introduced. Based on information from engine manufacturers and others, EPA estimated that engine oil change intervals will be extended by 10 percent due to the use of low sulfur diesel fuel. The exhaust system components – exhaust pipes and mufflers – typically fail because of corrosion of the pipe walls. Corrosion rates are increased by sulfuric acid present in diesel exhaust, which can condense on exhaust system walls. EPA estimated that the reduction in sulfuric acid-induced corrosion may extend exhaust system component life by 5 percent.

[75] This 7 percent rate is inconsistent with the 5 percent discount rate selected for the Second Prospective, but insufficient data were presented in EPA's RIA for the Tier 2 standards to adjust the fuel savings estimate to reflect a 5 percent discount rate.

These savings due to the use of low sulfur diesel fuel can be expressed as a savings in cents per gallon of low sulfur diesel fuel. These savings are delineated in Table VI-11.

Exhibit 3-11. Cost Savings for Diesel Sulfur Standards (cents/gallon)

	Cost Savings (cents/gallon)		
	Light HDDVs	**Medium HDDVs**	**Heavy HDDVs**
Extend Oil Change Intervals	1.34	0.99	0.60
Extend Exhaust Replacement Interval	0.14	0.10	0.04

4. Vehicle Emissions Inspection Programs

Vehicle I/M programs are designed to ensure that emission controls continue to operate properly over a vehicle's lifespan. Vehicle I/M programs were first introduced in the late 1970s, enabled by a provision in the 1977 Clean Air Amendments specifying that approval of State Implementation Plans would only be granted when "to the extent necessary and practicable" there will be "periodic inspection and testing of motor vehicles to enforce compliance with applicable emission standards."[76] The States responded by establishing programs that differed in detail but typically involved an "idle" test that was performed under no-load conditions by inserting a probe in the vehicle's tailpipe. Some programs also had visual tests to determine whether emission controls had been tampered with. Most programs also had "waiver" provisions that put an upper limit on what motorists had to spend to repair their vehicles. Once this amount had been expended, owners were excused from further expense regardless of the vehicle's emissions.

These State programs fell into two categories: "centralized" ("test-only") programs, where inspections are conducted at a relatively small number of large specialized facilities operated by the State or a State contractor; and "decentralized" ("test-and-repair") programs, where inspections occur at any of a large number of privately-owned repair shops certified to conduct emission inspections. In decentralized programs, I/M programs were often added onto existing safety inspection programs.

Because initial evaluations indicated that these programs were not as effective at reducing emissions as had been hoped, Congress established much more stringent requirements for State I/M programs in the CAAA. Congress directed the EPA to determine where State programs had failed and to develop program guidelines for avoiding or overcoming these failures. The EPA has developed a series of regulations, first promulgated in 1992,[77] that specify I/M program characteristics and the emission reduction credits these characteristics would receive. The MOBILE program is EPA's official tool for modeling the emission reduction effects of I/M programs.

To estimate the costs of I/M programs, Pechan developed two sets of estimates: costs per tested vehicle, which differ by program design, and the number of vehicles tested. Although some I/M programs were in place before the 1990 CAAA, all of the costs associated with these programs have been attributed to the CAAA in this study because many programs were substantially changed after the 1990 CAAA and EPA's 1992 I/M program regulations.

[76] 1977 Clean Air Act Amendments, Title 1, section 110, 2(g).

[77] "Inspection /Maintenance Program Requirements: Final Rule," 57 Fed Reg. No. 215, November 5, 1992.

a. Per Tested Vehicle Costs

The I/M program per vehicle cost estimates included in the First Prospective analysis were based on an EPA report from the early 1990s that focused on centralized, IM240-based programs (EPA, 1992). The actual adopted programs have been much more diverse than envisioned by the EPA report. Therefore, Pechan conducted an analysis of I/M costs based on recent information from actual programs. This analysis determined average per tested vehicle cost estimates for eight model I/M programs.

The eight model I/M programs were developed from recent information describing program characteristics. The majority of this information was obtained from two references (ETI, 2006 and ILEPA, 2005). Pechan also visited the websites for States' I/M programs to obtain additional information and/or confirm the accuracy of the information reported in these references. Exhibit 3-12 summarizes the eight model I/M programs.

Exhibit 3-12. Model I/M Programs Used in Estimating I/M Program Costs

Program Type	Test Type	Frequency
Centralized	Idle	Annual
Centralized	Idle	Biennial
Decentralized	Idle	Annual
Decentralized	Idle	Biennial
Centralized	Dynamometer	Annual
Centralized	Dynamometer	Biennial
Decentralized	Dynamometer	Annual
Decentralized	Dynamometer	Biennial

Note that for 2010, test type refers to the test performed on pre-1996 model year vehicles (1996+ model year vehicles are tested using OBD test), and that for 2020, all model programs are assumed to test vehicles using the OBD test exclusively.

Below we describe our approach for estimating each component of I/M costs per vehicle. These include the following: inspection fees, vehicle operating expense, costs associated with vehicle owners' time, and vehicle repair costs. After describing each of these costs, we then summarize total I/M costs per vehicle.

Inspection Fees

Pechan first analyzed the available information to identify average inspection fees charged and how these fees appeared to correlate with certain I/M program parameters.[78] Based on a review of the two aforementioned references and State websites, Pechan identified that average fees differed for centralized versus decentralized and annual versus biennial programs. The data did not indicate fee differences between idle-based and dynamometer-based (i.e., Acceleration Simulation Mode [ASM] or IM240) programs.[79] Using information from 2005, Pechan computed the following average inspection fees (all costs cited throughout this section are in 2005 dollars unless otherwise noted):

[78] Based on more detailed reviews of cost information for a sample of I/M programs, Pechan assumed that these fees cover not only the capital and operating costs incurred by inspection stations, but also each State's program administration and enforcement costs.

[79] IM240 is a test that involves running vehicles through a 240 second test cycle on a dynamometer under load.

- Centralized annual inspections = $11;
- Centralized biennial inspections = $19;
- Decentralized annual inspections = $26; and
- Decentralized biennial inspections = $35.

As described in the following sections, Pechan also developed estimates for (1) vehicle operating expense associated with traveling to/from inspection station; (2) opportunity cost related to owner's time spent driving to/from station and while waiting for inspection; and (3) average vehicle repair costs (net of fuel savings associated with repair). The following describes how these costs were estimated.

Vehicle Operating Expense

A review of I/M program information indicated that centralized I/M programs, which by their nature have fewer inspection stations than decentralized I/M programs, require vehicle owners to drive farther to obtain an inspection. Based on available information,[80] Pechan assumed the following travel distances:

- Centralized programs − 10 miles (5 miles each direction); and
- Decentralized programs − 6 miles (3 miles each direction).

To estimate vehicle operating costs per mile (43.2 cents), Pechan used the Internal Revenue Service's 2005 allowable mileage rate for deducting automobile operating costs (43.2 cents per mile).[81] By combining the mileage and the operating cost per mile estimates, Pechan estimated the following operating costs per tested vehicle: centralized I/M programs = $4.32, and decentralized I/M programs = $2.59.

Costs Associated with Vehicle Owner's Time

Different I/M program designs result in varying amounts of required time to obtain an inspection. Total time includes the time spent traveling to/from the inspection station, the time spent waiting while the test is performed, and the time spent waiting before/after the test is performed. Based on the available information, Pechan assumed the following average times by I/M program type:

- Decentralized idle-based I/M = 25 minutes;
- Decentralized dynamometer-based I/M = 30 minutes;[82,83]
- Centralized idle-based I/M = 55 minutes; and
- Centralized dynamometer-based I/M = 60 minutes.

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[80] An analysis performed of Arizona's centralized I/M program used an average one-way travel distance of 4.5 miles (Harrington and McConnell, 1999).

[81] This value represents the average of the IRS mileage of 40.5 cents per mile for the first eight months of the year and 48.5 cents per mile for the final four months.

[82] Dynamometer-based I/M programs refer to ASM and IM240 test I/M programs.

[83] In some cases, owners of vehicles requiring decentralized idle-based I/M or decentralized dynamometer-based I/M may leave their vehicles at an auto repair shop for this I/M when they go in for routine maintenance (e.g., an oil change or tune-up). In such cases, there may be no incremental waiting time for the vehicle owner (e.g., if the owner is at work while the vehicle is at the repair shop). To the extent that this occurs, we may overestimate the time losses experienced by vehicle owners.

These estimates were derived from the following information sources and assumptions. For *centralized dynamometer-based I/M* programs, Pechan assumed an average 45 minutes for the travel time to/from the station and for the wait before/after test is performed based on a report citing estimates ranging from 45 to 60 minutes for centralized programs (NRC, 2001). An estimate of 15 minutes was used to reflect the time spent performing a dynamometer-based test based on a 12 to 15 minute dynamometer test estimate reported in a recent report (MADEP, 2002). For *centralized idle-based I/M* programs, Pechan reduced the 15 minute test time to 10 minutes to reflect the fact that the idle test is simpler/quicker to perform than dynamometer tests. Further support for this estimate comes from real-time data indicating the average time spent in conducting an OBD and gas cap test was 6 minutes and 45 seconds (PADEP, 2004).[84] While idle tests take less time to perform than dynamometer tests, they should take somewhat more time than OBD tests.

In Appendix B, Pechan describes how inspection time estimates were developed to support derivation of average per vehicle costs for decentralized OBD-only I/M programs. To estimate the average total time spent by vehicle owners in obtaining idle and dynamometer-based decentralized tests, Pechan made adjustments to the total 20 minute estimate developed for a decentralized OBD-only program. For *decentralized dynamometer-based I/M* programs, Pechan assumed an additional 10 minutes for this test based on time estimates reported in a Massachusetts report (MADEP, 2002). For *decentralized idle-based I/M* programs, Pechan assumed an additional 5 minutes for an idle test relative to an OBD test. This time differential is consistent with the assumptions used for the centralized program in that idle tests are assumed to take 5 minutes less to perform than dynamometer tests.

To estimate the value to the vehicle owner of the time spent acquiring an inspection, the Project Team used an estimate of the opportunity cost of time derived from wage rates. Although it is not clear that time spent acquiring an inspection will in all cases represent lost time at work, we estimated the value of lost time in this case using the national average pre-tax wage rate, plus an estimate of average prorated per-hour benefits. Our estimate of this value is $26.06 per hour, reflecting wages or salaries, benefits, and taxes.[85]

The Project Team concluded that use of pre-tax wage rate plus benefits is a reasonable approximation of the social cost of lost time in the context of inspection programs for two reasons. First, using pretax wages plus benefits to value lost market work time is consistent with a recent peer-reviewed EPA guidance document on the value of lost time (EPA, 2005) and DOT guidance for lost travel time (DOT, 1997 and 2003). Second, our approach largely balances unquantifiable factors that might lead to overestimates with those that might lead to underestimates of this value. For example, the value of lost market work time may be argued to potentially overestimate the lost time from inspection programs, because in at least some cases, the lost time is more accurately characterized as lost non-market work time or leisure time, which is typically valued at a lower rate. At the same time, however, some research suggests that there is an additional disamenity factor associated with time spent waiting (e.g., DOT, 1997 and 2003), which may or may not apply in the context of vehicle inspections.

[84] This estimate excludes the time bringing the vehicle into the test bay and completing/affixing the inspection sticker, but these activities would increase this estimate only marginally.

[85] This value is derived from the Department of Labor, Bureau of Labor Statistics (BLS) Employer Costs for Employee Compensation, part of the 2006 National Compensation Survey, and reflects the average of quarterly BLS estimates for 2005 (BLS, 2006). The stated value includes wages, salaries, and employee benefits for all nonfarm private and state and local government workers. The full employer costs for benefits includes: insurance benefits - life, health, and disability; legally required benefits, including Social Security, Medicare, unemployment insurance, and workers' compensation; paid leave benefits (vacations, holidays, sick leave, and other leave); and retirement and savings benefits per hour worked.

Vehicle Repair Cost (Net of Fuel Savings)

Vehicle repair costs associated with I/M programs are a function of repair incidence (inspection failure rates) and the average cost of repair. For this analysis, Pechan estimates an average $300 spent for repairs for vehicles failing dynamometer and OBD-based tests. This $300 per repaired vehicle assumption is based on data from Wisconsin (estimated average repair cost for first retest pass of $304 in 2003 and $306 in 2004 for all tests, where IM240 and OBD-tests comprise more than 98 percent of the I/M tests performed), a 2005 Arizona study that noted average repair costs of "approximately $300" for vehicles undergoing dynamometer/OBD tests, and an EPA study that estimates an average OBD repair cost between $210 and $481 for vehicles repaired with 100,000+ miles (WIDOT, 2006; ERG, 2005; and Gardetto, 2002).[86]

Because they use different approaches for identifying failing vehicles, different inspection protocols can be expected to yield different rates of inspection failure. Although failure rates will differ depending on detailed program parameters (e.g., model year exemptions, emission cutpoints), it was not feasible to develop model cost programs to account for all such parameters. Based on information from available I/M program studies, Pechan assumed the following average inspection failure rates:[87]

- Annual idle tests – 7 percent;
- Biennial idle tests – 10.3 percent;
- Annual dynamometer tests – 14 percent; and
- Biennial dynamometer tests – 20.6 percent.

The estimated failure rate for an annual dynamometer-based I/M program was based on Wisconsin data indicating an approximate 14 percent failure rate in both 2003 and 2004 from the more than 700,000 vehicles tested in each year (as noted earlier, more than 98 percent of vehicles tested in Wisconsin undergo either an IM240 or OBD test).[88] Further support for the 14 percent estimate comes from a detailed study of 1995/1996 data from Arizona's annual IM240-based program, which indicated a 13.6 percent inspection failure rate (Ando, McConnell, and Harrington, 1999).[89]

The annual idle test failure rate was estimated at one-half the dynamometer test failure rate based on studies in two States (Wisconsin and New York) that provided IM240 and idle test failure rates for 2003 and 2004 (WIDOT, 2006 and NYSDEC, 2004 and 2005).

The biennial test failure rate for dynamometer-based programs was estimated at 20.6 percent based on Arizona IM240 data indicating that about 15 percent of vehicles will fail for the first time within 24 months of passing an original test and that 40 percent of previously failed/fixed vehicles will fail in their next test within 24 months – i.e., 0.15 + (0.4 x 0.14) = 0.206 (Wenzel and Brown, 2001). In keeping with the annual idle test failure rate assumption, the biennial idle test failure rate (10.3 percent) was estimated at one-half the biennial dynamometer test rate.

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[86] EPA states with 95 percent statistical confidence that repair costs are within this range for OBD failures defined by illumination of the malfunctioning indicator light.

[87] These failure rates represent averages across all affected vehicles. Although failure rates may vary by vehicle model year, the available data were not sufficient to estimate failure rates by model year.

[88] An EPA review of Wisconsin data comparing IM240 and OBD failure rates concluded that "…the number of vehicles failing each test was roughly the same when using final cutpoints for all three pollutants" (EPA, 2002).

[89] This study found that 135,734 of 995,904 tested vehicles failed in 1995/1996.

Current I/M programs are generally a mix of OBD testing for 1996+ model year vehicles and idle/dynamometer testing for older vehicles. As noted above, failure rates for idle tested vehicles are assumed to be half those of vehicles tested using dynamometer/OBD-based tests. To properly estimate total repair costs in such programs, it is necessary to estimate, for each analysis year, the proportion of total vehicles that are required to obtain idle-based tests and the proportion required to obtain OBD-based tests. The OBD-based test proportion is zero in 2000 because OBD-based tests were not yet required by EPA in this year.[90] A value of zero was used for idle-based tests in 2020 because MOBILE6.2 indicates that there will be no pre-1996 model year light-duty gasoline vehicles existing in 2020. Therefore, we assume that 100 percent of affected vehicles would be subject to an OBD-based test in 2020. To calculate 2010 repair costs for programs with current idle testing requirements, Pechan assumed that 13 percent of all tested vehicles would be pre-1996 model year vintage, and, therefore, subject to an idle-based test (the other 87 percent would be subject to an OBD-based test). The 13 percent value represents the proportion of total light-duty gasoline vehicles in 2010 that are pre-1996 model year vintage in MOBILE6.2.

The EPA has developed estimates of fuel economy increases associated with repairs performed in response to I/M program inspections since at least 1992 (EPA, 1992). Based on findings from the most extensive in-use study identified, Pechan assumed an average improvement of 0.75 miles per gallon for each repair (NRC, 2001). To estimate the per vehicle value of this improvement, Pechan utilized the aforementioned inspection failure rates and proportions of total vehicles undergoing each type of test in each year, and the following assumptions: average of 12,000 miles of travel per year, baseline average fuel efficiency of 20 miles per gallon, and a gasoline price of $2.34 per gallon (DOE, 2006).

Summary of I/M Cost Estimates

Exhibit 3-13 presents the estimated year 2000 costs per vehicle for each individual cost component (in year 2005 dollars). Exhibit 3-14 displays inspection (inspection fee, plus vehicle operating expense, plus vehicle owner's time cost), vehicle repair (net of fuel savings), and total cost estimates in 2005 dollars. The 2005 year total costs were adjusted to 1999 prices using 1999 and 2005 GDP implicit price deflators. Exhibit 3-15 displays the final per vehicle tested cost estimates in 1999 dollars. When the total I/M costs shown in TableVI-15 were multiplied by the number of registered vehicles, all biennial program costs were first divided by 2, since vehicles in biennial inspection programs only incur these costs every other year.

5. Clean Fuel Fleet Program (CFFP)

The CAAA of 1990 mandated the implementation of a fuel neutral Clean Fuel Fleet Program (CFFP) beginning in model year 1998 for those nonattainment areas designated as serious, severe, and extreme for ozone or with a design value above 16 ppm for CO. The Act, however, specifically prohibits EPA from requiring vehicle manufacturers to produce clean fuel fleet vehicles (CFFVs). The statute also provided an opt-out opportunity for those areas wishing to use other methods to meet their air quality objectives. Of the original areas covered by the CAAA, only six areas have not opted-out. They are Atlanta, Metropolitan Washington, DC, Chicago-Gary-Lake County, Milwaukee-Racine, Denver-Boulder, and Baton Rouge. Costs for this program have not been estimated here.

[90] Note that Pechan did not estimate repair costs for the vehicles that undergo an anti-tampering (ATP)/gas cap check in this year because of the very small assumed failure rate (data for New York indicates an 0.2 percent failure rate for an ATP/gas cap check).

6. Transportation Conformity

The primary cost impact of the transportation conformity rule involves the increased requirements for Metropolitan Planning Organizations (MPOs) to perform regional transportation and emissions modeling and document the regional air quality impacts of transportation plans and programs. A U.S. Department of Transportation (DOT) survey in September 1992 of MPOs in 98 ozone nonattainment areas indicated that during Phase I of the interim period, most MPOs spent less than $50,000 for a conformity determination on the transportation plan and Transportation Improvement Program (TIP). Of the 68 MPOs responding, 76 percent spent less than $50,000, 21 percent spent between $50,001 and $100,000, and 3 percent spent between $100,001-250,000. MPOs serving populations over one million had higher conformity costs than MPOs serving smaller populations.

Exhibit 3-13. Estimated Year 2000 Costs per Vehicle Tested by I/M Program Type and Detailed Cost Component (in 2005 Dollars)

	Costs of Inspection					Repair Cost/Fuel Savings			
Model Program	**Inspection Fee**	**Travel, Wait, & Inspection Time (mins)**	**Cost of Motorist Time**	**Vehicle Operating Expense**	**Total Inspection Cost**	**Vehicle Repair Cost**	**Fuel Economy Savings**	**Total Repair Cost Net of Fuel Savings**	**Total Cost**
Centralized Annual Idle	$11.00	55	$23.89	$4.32	$39.21	$21.00	-$3.55	$17.45	$56.50
Centralized Annual Dynamometer	$11.00	60	$26.06	$4.32	$41.38	$42.00	-$7.10	$34.90	$76.50
Decentralized Annual Idle	$26.00	25	$10.86	$2.59	$39.45	$21.00	-$3.55	$17.45	$57.00
Decentralized Annual Dynamometer	$26.00	30	$13.03	$2.59	$41.62	$42.00	-$7.10	$34.90	$76.50
Centralized Biennial Idle	$19.00	55	$23.89	$4.32	$47.21	$30.90	-$5.23	$25.67	$73.00
Centralized Biennial Dynamometer	$19.00	60	$26.06	$4.32	$49.38	$61.80	-$10.45	$51.35	$100.50
Decentralized Biennial Idle	$35.00	25	$10.86	$2.59	$48.45	$30.90	-$5.23	$25.67	$74.00
Decentralized Biennial Dynamometer	$35.00	30	$13.03	$2.59	$50.62	$61.80	-$10.45	$51.35	$102.00

Note: Total cost is rounded to nearest half-dollar.

Exhibit 3-14. Estimated Costs per Vehicle Tested by I/M Program Type, Major Cost Component, and Year (in 2005 Dollars)

	2000			2010			2020		
Model I/M Program	**Total Inspection Cost**	**Vehicle Repair Cost**	**Total Cost**	**Total Inspection Cost**	**Vehicle Repair Cost**	**Total Cost**	**Total Inspection Cost**	**Vehicle Repair Cost**	**Total Cost**
Centralized Annual Idle	$39.21	$17.45	$56.50	$39.21	$32.63	$72.00	$39.21	$34.90	$74.00
Centralized Annual Dynamometer	$41.38	$34.90	$76.50	$41.38	$34.90	$76.50	$41.38	$34.90	$76.50
Decentralized Annual Idle	$39.45	$17.45	$57.00	$39.45	$32.63	$72.00	$39.45	$34.90	$74.50
Decentralized Annual Dynamometer	$41.62	$34.90	$76.50	$41.62	$34.90	$76.50	$41.62	$34.90	$76.50
Centralized Biennial Idle	$47.21	$25.67	$73.00	$47.21	$48.01	$95.00	$47.21	$51.35	$98.50
Centralized Biennial Dynamometer	$49.38	$51.35	$100.50	$49.38	$51.35	$100.50	$49.38	$51.35	$100.50
Decentralized Biennial Idle	$48.45	$25.67	$74.00	$48.45	$48.01	$96.50	$48.45	$51.35	$100.00
Decentralized Biennial Dynamometer	$50.62	$51.35	$102.00	$50.62	$51.35	$102.00	$50.62	$51.35	$102.00

Exhibit 3-15. Estimated Total Costs per Vehicle Tested by I/M Program Type and Year (in 1999 Dollars)

Model I/M Program	**2000 Total Cost**	**2010 Total Cost**	**2020 Total Cost**
Centralized Annual Idle	$49.00	$62.50	$64.50
Centralized Annual Dynamometer	$66.00	$66.00	$66.00
Decentralized Annual Idle	$49.50	$62.50	$64.50
Decentralized Annual Dynamometer	$66.50	$66.50	$66.50
Centralized Biennial Idle	$63.50	$82.50	$85.50
Centralized Biennial Dynamometer	$87.50	$87.50	$87.50
Decentralized Biennial Idle	$64.50	$83.50	$86.50
Decentralized Biennial Dynamometer	$88.50	$88.50	$88.50

Notes:
Dynamometer refers to IM240 or ASM-based tests.
Total cost is rounded to nearest half-dollar.

If it is assumed that the ozone areas surveyed by DOT in September 1992 are representative of all nonattainment areas, the estimated total annual conformity cost for the nation's transportation plans and TIPs is $16.6 million. This estimate is uncertain in part because it was developed during the formative stages of the transportation conformity rule. Although no definitive cost studies have been prepared since then, EPA actions subsequent to the initial promulgation of the conformity rule, in response to State and local concerns, are expected to reduce costs. These cost reducing actions include that transitional ozone areas under the new NAAQS will have a simpler conformity process. In addition, all other areas will be using the 1997 revised conformity rule, which streamlines conformity requirements (62FR43779, 1997).

7. Heavy-Duty Diesel Defeat Device Settlements

On October 22, 1998, the Department of Justice and EPA announced an $83.4 million total penalty against diesel manufacturers. Under this settlement, seven major manufacturers of diesel engines will spend more than one billion dollars to resolve claims that they installed computer devices in heavy-duty diesel engines which produced illegal amounts of air pollution emissions. This settlement will prevent 75 million tons of NO_x emissions nationwide by the year 2025. The companies involved are Caterpillar, Inc., Cummins Engine Company, Detroit Diesel Corporation, Mack Trucks, Inc., Navistar International Transportation Corporation, Renault Vehicles Industriels, s.a., and Volvo Truck Corporation.

The seven companies sold 1.3 million heavy-duty diesel engines containing illegal defeat devices, which allow an engine to pass the EPA emissions test, but then turn off emission controls during highway driving. As a result, these engines emit up to three times the current level of NO_x.

In the enforcement actions settled by the decree, EPA claimed that defendants and other engine manufacturers violated the Clean Air Act and its implementing regulations by selling engines that emitted excess pollution and by failing to disclose how the engines operated in real world conditions. A key component of the decree required defendants to meet, by October 1, 2002, engine emission standards that would not have otherwise been be applicable until January 2004. This is referred to as the *pull ahead requirement*.

The decree provided that if defendants were not able to meet the October 1, 2002 deadlines, they could continue to sell non-compliant engines through three mechanisms: (1) payment of Non-Conformance Penalties (NCPs) to be calculated to correspond to the cost of compliant engines so as to maintain a level playing field between defendants and those engine manufacturers who met the deadline, (2) utilization of emissions averaging, banking, and trading, by which defendants can generate emission credits towards compliance through reducing emissions in other areas, and (3) a limited provision allowing post-deadline sales of non-compliant engines through matching pre-deadline sales of compliant engines.

For heavy-heavy duty engines, the NCPs are based on the compliance costs associated with lowering the emissions from 6.0 g/bhp-hr NMHC + NO_x to the 2004 standard of 2.5 g/bhp-hr NMHC + NO_x. (This analysis was not performed in the standard-setting rules, and therefore the cost estimates in the standard-setting rule and the NCP proposal are not comparable.) The estimated annual costs for an average model year 2004 vehicle meeting the 2.5 g/bhp-hr NMHC + NO_x emission standard were estimated to be (by component):

Amortized fixed	=	$522
Engine manufacturer hardware	=	$1,300
Manufacturer warranty cost	=	$100
Vehicle manufacturer cost	=	$100

Fuel cost	=	$708 in year 1
Other operating (rebuild)	=	$274 in year 5

Because the NCP cost of meeting the pull ahead standards is a short term cost that is only incurred by truck purchasers for a limited set of model years and the methods used by EPA for computing the associated costs are inconsistent with those developed for Federal emission standards, no CAAA-related cost for this action is included in this with-CAAA scenario cost analysis. In addition, costs to meet the applicable emission standards based on EPA's assessments of likely compliance strategies and associated costs may already account for these CAAA scenario costs.

Cost Summary

Exhibit 3-16 summarizes the motor vehicle unit costs used in this analysis. Individual motor vehicle provisions are listed with costs noted by vehicle type in year 1999 dollars. For the fuels provisions of the CAAA, some benefits and costs only occur in certain seasons. Phase II RVP and Phase II Federal reformulated gasoline limits only result in ozone season costs, while oxygenated fuels produce CO season (winter time) costs. All other fuels programs listed in Exhibit 3-16 produce year round costs.

Exhibit 3-17 summarizes the motor vehicle costs for 2000, 2010, and 2020 given the unit cost information provided earlier in this chapter. Costs are also organized by title, with LEV program and I/M costs allocated to Title I: Nonattainment, with the remaining motor vehicle measure costs allocated to Title II: Motor Vehicles.

Exhibit 3-16. Motor Vehicle Unit Costs by Provision (in 1999 Dollars)

		Cost Estimate by Vehicle Type in 1999 Dollars								
Provision	**Cost Unit**	**LDGV**	**LDGT1**	**LDGT2**	**MC**	**HDGV**	**LDDV**	**LDDT**	**HDDV2B**	**LHDDV**
Emission Standards:										
-Tier 1 Tailpipe Standards: VOC	Sales	36.23	32.66	10.90						
-Tier 1 Tailpipe Standards: NO_x	Sales	113.37	78.02	42.18		14.90			72.63	72.63
-Tier 2 Tailpipe Standards	Sales	45.72	73.69	176.21						
-Cold Temperature CO Standard	Sales	17.94	30.01	45.96						
-Evaporative Controls	Sales	-1.51	6.03	6.03		-17.04				
-On-Board Vapor Recovery System										
costs in 2000	Sales	4.12	3.94	3.94						
costs in 2010 and 2020	Sales	3.95	3.75	3.75						
-On-Board Diagnostics	Sales	55.29	55.29	55.29						
-Heavy Duty Engine Standard (2 gm equiv)	Sales								175.41	175.41
-Low Emission Vehicles (California LEVII and National Low Emission Vehicle Program)										
TLEV	Sales	66.09	66.09							
LEV	Sales	103.82	103.82							
ULEV	Sales	123.30	123.30							
ZEV	Sales	5,213.95	5,213.95							
-Heavy Duty Vehicle 2007 Emission Standards										
costs in 2010	Sales					161.13			1,620.32	1,620.32
costs in 2020	Sales					139.27			1,487.32	1,487.32
Fuels:										
-Phase II RVP Limits	Cents/gallon	0.2	0.2	0.2	0.2	0.2				
-Federal Reformulated Gasoline: Phase I	Cents/gallon	4.3	4.3	4.3	4.3	4.3				
-Federal Reformulated Gasoline: Phase II	Cents/gallon	1.3	1.3	1.3	1.3	1.3				
-Oxygenated Fuels	Cents/gallon	4.2	4.2	4.2	4.2	4.2				
-Low-Sulfur Diesel Fuel (0.05% sulfur in 1993)	Cents/gallon						2.5	2.5	2.5	2.5
-California Phase I Reformulated Gasoline	Cents/gallon	1.7	1.7	1.7	1.7	1.7				
-California Phase II Reformulated Gasoline	Cents/gallon	14.3	14.3	14.3	14.3	14.3				
-California Reformulated Diesel	Cents/gallon						6.5	6.5	6.5	6.5
-Gasoline Fuel Sulfur Limits										
costs in 2010	Cents/gallon	1.7	1.7	1.7	1.7	1.7				
costs in 2020	Cents/gallon	1.3	1.3	1.3	1.3	1.3				
-Diesel Fuel Sulfur Limits (15 ppm)										
costs in 2010	Cents/gallon						3.2	3.2	3.2	3.1
costs in 2020	Cents/gallon						3.7	3.7	3.7	3.6
Inspection/Maintenance Programs:										
See costs summarized in Exhibit 3-16										

Exhibit 3-17. Motor Vehicle Program Costs in 2000, 2010, and 2020

	Annual Cost (million 1999$)		
Program	**2000 with CAAA**	**2010 with CAAA**	**2020 with CAAA**
Title I			
National Low Emission Vehicles Program	$278	$1,329	$1,359
California Low Emission Vehicles II Program	$331	$868	$878
Inspection and Maintenance (I/M) Programs	$3,813	$5,098	$5,933
Subtotal: Title I Motor Vehicle Costs	**$4,423**	**$7,295**	**$8,169**
Title II			
Tier 1 Tailpipe Standards: VOC	$571	$526	$540
Tier 1 Tailpipe Standards: NOx	$1,745	$1,576	$1,593
Evaporative Controls (New Evaporative Emissions Test Procedure)	$10	$24	$36
Cold Temperature CO Standard	$403	$427	$474
On-board Vapor Recovery System	$70	$64	$67
On-board Diagnostics	$952	$914	$963
Tier 2 Tailpipe Standards	$0	$1,059	$1,182
Heavy-Duty Vehicle Standard (2 Gram Equivalent)	$0	$124	$126
Heavy-Duty Vehicle 2007 Emission Standards	$0	$1,755	$1,594
Phase II RVP Limits	$129	$153	$176
Oxygenated Fuels	$136	$174	$213
Federal Reformulated Gasoline: Phase I	$1,170	$1,357	$1,529
Federal Reformulated Gasoline: Phase II	$150	$174	$196
Gasoline Fuel Sulfur Limits	$0	$2,608	$2,291
California Phase I Reformulated Gasoline	$241	$298	$354
California Phase II Reformulated Gasoline	$1,975	$2,445	$2,903
Low-sulfur Diesel Fuel (0.05% Sulfur in 1993)	$777	$995	$1,185
California Reformulated Diesel	$122	$160	$197
Diesel Fuel Sulfur Limits (15 ppm)	$0	$1,550	$2,112
Subtotal: Title II Motor Vehicle Costs	**$8,451**	**$16,382**	**$17,731**
Total Motor Vehicle Control Costs	**$12,874**	**$23,676**	**$25,900**

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CHAPTER 4 - NONROAD ENGINES/VEHICLES

We developed nonroad engine and nonroad vehicle emission estimates using EPA's Office of Transportation and Air Quality's (OTAQ) NONROAD2004 model. The direct cost estimates presented in this chapter were developed consistent with those results. Nonroad equipment categories not included in NONROAD (e.g., refueling emissions) are discussed in Chapter 6, 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 in detail in Chapter 5 of the accompanying emissions analysis report, 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 engine growth rates used here are consistent with the national NONROAD model data/assumptions that have been used in multiple EPA regulatory analyses.[91]

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 SAB Council and AQMS reviews of the 2003 analytical plan.

[91] Our analysis of the available data from AEO 2005 suggests that the AEO data would yield moderately higher fuel consumption estimates than NONROAD in aggregate. For individual vehicle categories, however, the difference between the AEO-based projections and NONROAD projections could be significant. In addition, the fuel mix implied by the AEO data is skewed more heavily toward natural gas than the mix associated with the NONROAD data.

<u>Summary of Approach</u>

Future year nonroad engine program costs are estimated for the control measures reflected in the emission projections analysis.[92] Nonroad engine control costs are calculated based on one of the following algorithms:

Cost per new engine -
Cost = projected engine sales * production cost ($/new engine)

Cost per gallon fuel consumed -
Cost = projected fuel consumption * cost per gallon ($/gallon)

Cost per ton pollutant reduced -
Cost = projected emission reduction * cost per ton reduced ($/ton)

Exhibit 4-1 provides a list of the nonroad source control programs modeled in this analysis, as well as the basis for the costs. For most nonroad engine categories, the Project Team estimated the per engine costs for modifying equipment/vehicles to meet EPA standards.[93] Costs for standards affecting these categories are calculated based on a per-engine production cost applied to projected sales. Projected sales data for the years of interest are typically reported by EPA in the supporting RIA or Regulatory Support Document. Except where noted in the discussion below, projected sales data were typically estimated using base year sales obtained directly from the engine manufacturers, and projected to future years based on the same growth assumptions used to estimate total in-use populations for EPA's NONROAD model. Costs for the nonroad diesel sulfur standards are calculated based on a per-gallon cost applied to projected fuel consumption for the affected nonroad engines. In addition, for all of these standards, EPA's cost analyses include variable costs that are marked up at a rate of 26-29 percent to account for the engine manufacturers overhead and profit. For the spark-ignition (S-I) marine engines (exhaust standards) and for locomotive and diesel commercial marine engines, we relied on cost effectiveness calculations based on the annualized cost per ton of reduction.

To generate the cost estimates presented in this chapter, the Project Team relied upon several unit cost values from EPA regulatory impact analyses developed in support of the rules and programs listed in Exhibit 4-1. A limited number of these analyses assume that the costs of CAAA-related nonroad engine requirements will decline by 20 percent with each doubling in the cumulative production of affected vehicles. Although learning curve impacts are likely to reduce the cost of the Amendments over time, we were unable to identify any studies quantifying the magnitude of the learning effect for nonroad vehicles and engines. In the absence of such studies, the Project Team decided to present cost estimates for nonroad vehicles that do not reflect any adjustments to account for learning. In the few cases where the available unit cost estimates reflect learning curve impacts, the project team estimated the extent to which these values had been reduced due to learning and generated revised unit cost estimates that reflected no learning curve impacts.

[92] See "Emission Projections for the Clean Air Act Second Section 812 Prospective Analysis, Draft Report" for a discussion of the emission projection methodology and the control assumptions (Pechan and IEC, 2006).

[93] Throughout most of this chapter, we present unit cost estimates in the year's dollars used in the supporting documentation (e.g., the regulatory impact analysis for a rule). After estimating the total costs associated with each rule based on these unit cost values, we convert the total annual cost of each rule to year 1999 dollars using the GDP deflator.

Exhibit 4-1. List of Nonroad Programs for Which Costs were Modeled

Standard	Cost basis
All Small Spark-Ignition Engine rules (Includes Phase 1 and 2, Class I-V, Handheld and Non-handheld categories)	costs per engine
Large Spark-Ignition (S-I) rule	costs per engine
Snowmobiles	costs per engine
ATVs	costs per engine
Off-Highway Motorcycles	costs per engine
Spark-Ignition Marine Evaporative	costs per engine
Spark-Ignition Marine Exhaust	cost per ton
Tier 2 Diesel Marine	costs per engine
Tier 1 - 4 Diesel Engines	costs per engine
Nonroad Diesel Fuel Sulfur	costs per gallon fuel
Commercial Marine	cost per ton
Locomotive	cost per ton

Major Programs And Analysis Methods

The following sections provide a discussion of the general requirements for each major nonroad engine standard, and the method and source of the data for estimating costs. Note that only three standards were in effect in the year 2000, including the Small Spark-Ignition Phase 1, Spark-Ignition recreational marine, and Tier 1 nonroad diesel standards.

Small S-I Engine Standards

EPA's regulatory program for reducing NO_x, hydrocarbon (HC**{**tc "hydrocarbon (HC " \f D **}**), and CO emissions from SI engines has been issued in phases. The initial (Phase 1) regulation was finalized in July 1995. In December 1997, EPA proposed Phase 2 standards for nonroad, small spark-ignition engines. The small gasoline engine regulations affect small handheld and non-handheld equipment used in a variety of applications, including lawn and garden, small farm and construction, and light industrial applications. All engines were required to meet Phase 1 emission standards since 1997. For non-handheld applications, more stringent Phase 2 standards phase in between 2001 and 2007, while for handheld applications, Phase 2 standards phase in between 2002 and 2007.

EPA further distinguishes handheld equipment based on engine displacement and horsepower, creating three separate classes of engines, including Class III, IV, and V, while non-handheld equipment are separated into Class I and Class II engine categories. Emission standards vary for these classes of engines.

Exhibit 4-2 presents the data compiled for computing Phase 1 and Phase 2 small S-I costs for the years 2000, 2010, and 2020. Note that Phase 1 costs only apply in 2000, and the more stringent Phase 2 standards and associated costs apply in 2010 and 2020.

For Phase 1 and 2 standards, EPA estimated per engine costs to the engine manufacturer to install the necessary emission control technology, including variable hardware and production costs (EPA, 1995; EPA, 1999a; EPA, 2000). Fuel savings are expected and considered in adjusting the per engine costs. For Class V engines, the fuel savings outweigh the variable and fixed costs. In addition, estimated sales of these engines for the relevant years were reported by EPA (EPA, 1999a; EPA, 2000). Note that for the year 2000, only sales data for all non-handheld and handheld engines combined were reported. The distribution of sales by Class for the later years reported in the Phase 2 rulemaking did not change from year to year and was applied for 2000.

Exhibit 4-2. Small S-I Engine Cost Inputs

Year 2000			
Standard	**Affected HP**	**Engine Sales**	**Cost per engine (1993 $)**
Phase 1 Small S-I Handheld Class III	<1 hp	8,425,138	2
Phase 1 Small S-I Handheld Class IV	>1 and <3 hp	3,027,285	2
Phase 1 Small S-I Handheld Class V	<3 and <11 hp	1,449,032	3
Phase 1 Small S-I Non-handheld Class I	<3 and <6 hp	9,281,041	3
Phase 1 Small S-I Non-handheld Class II	<6 and <25 hp	568,346	4
Year 2010 Small S-I Cost Data			
Standard	**Affected HP**	**Engine Sales**	**Cost per engine (1998 $)**
Phase 2 Small S-I Handheld Class III	<1 hp	1,637,632	26
Phase 2 Small S-I Handheld Class IV	>1 and <3 hp	10,474,125	23
Phase 2 Small S-I Handheld Class V	<3 and <11 hp	661,246	24
Phase 2 Small S-I Non-handheld Class I	<3 and <6 hp	8,928,931	5
Phase 2 Small S-I Non-handheld Class II	<6 and <25 hp	3,208,306	-43
Year 2020 Small S-I Cost Data			
Standard	**Affected HP**	**Engine Sales**	**Cost per engine (1998 $)**
Phase 2 Small S-I Handheld Class III	<1 hp	1,937,572	23
Phase 2 Small S-I Handheld Class IV	>1 and <3 hp	12,375,287	20
Phase 2 Small S-I Handheld Class V	<3 and <11 hp	800,697	16
Phase 2 Small S-I Non-handheld Class I	<3 and <6 hp	9,354,478	5
Phase 2 Small S-I Non-handheld Class II	<6 and <25 hp	3,361,212	-43

Large S-I Engine Standards

Engines covered by these standards are large (greater than 25 horsepower) industrial S-I engines powered by gasoline, liquefied petroleum gas (LPG), or compressed natural gas (CNG). These engines are used in commercial and industrial applications, including forklifts, electric generators, airport baggage transport vehicles, and farm and construction applications.

In 2002, EPA adopted two tiers of emission standards to reduce exhaust emissions of HC, NO_x, and CO from large SI engines, with the first tier starting in 2004, and the Tier 2 standards starting in 2007. Manufacturers must also take steps starting in 2007 to reduce evaporative emissions, such as using pressurized fuel tanks.

Exhibit 4-3 presents the data compiled for computing Tier 1 and Tier 2 large S-I costs for the years 2010 and 2020 (EPA, 2002a). Manufacturer engine and equipment costs vary for gasoline, LPG, and CNG. Because the sales data represent all large S-I engines combined, a composite cost and savings reported for the various engine types combined was used for this analysis. This rule is predicted to result in an overall cost savings, since the fuel savings significantly outweigh the cost of compliance with the standards. Fuel savings were calculated based on the estimated fuel savings in EPA's regulatory impact analysis of the standards.[94]

Exhibit 4-3. Large S-I Engine Cost Inputs

2010 Large S-I Cost Data

Standard	Engine Sales	Cost per Engine (1999 $)	Cost per engine with Fuel Savings* (1999 $)
Large S-I	169,000	$604	($1,233)

2020 Large S-I Cost Data

Standard	Engine Sales	Cost per Engine (1999 $)	Cost per engine with Fuel Savings* (1999 $)
Large S-I	208,000	$604	($1,559)

*Costs represent a savings

Recreational Land-based Engine Standards

EPA promulgated standards for recreational gasoline engines, including snowmobiles, off-highway motorcycles, and all-terrain vehicles (ATVs) in a 2002 rulemaking. These standards affect engines manufactured in 2006 and are phased in up to the year 2012. Exhibit 4-4 presents the cost inputs as compiled from EPA's RIA for these standards (EPA, 2002b). These costs include annual per engine fixed and variable costs, as well as fuel savings, resulting in an overall savings for some equipment (e.g., snowmobiles). Note that fuel savings were reported as discounted in EPA's RIA and were annualized to match the fixed and variable costs. Fuel savings per year were estimated for each equipment type accounting for a 25 percent fuel savings by converting from 2-stroke to 4-stroke engines, as well as a fuel savings from control of permeation emissions. Gallons of fuel saved were then multiplied by the 2005 cost of gasoline, and these savings were used to adjust the per unit costs.

[94] Our analysis of the RIA indicates that the fuel savings estimates presented in Exhibit 4-3 are inconsistent with the analytic requirements of the Second Prospective. More specifically, the RIA estimates fuel savings on a cash flow basis (i.e., the fuel savings for 2010 reflect the fuel savings realized in 2010 for engines sold in 2010 and prior years). For the Second Prospective, the lifetime net present value of the fuel savings associated with engines sold in 2010 and 2020 would be more appropriate. For the purposes of this draft, we have not yet developed such net present value estimates, but our preliminary analysis of the fuel savings data in the RIA suggests that the net present value fuel savings may be significantly higher than the cash flow-based estimates presented in Exhibit 4-3.

Exhibit 4-4. Recreational Land-Based Engine Cost Inputs

Standard	2010 Engine Sales	Cost per Engine (2001 $)
Snowmobiles	210,367	(95)
ATVs	985,754	87
Off-Highway Motorcycles	216,542	125

Standard	2020 Engine Sales	Cost per Engine (2001 $)
Snowmobiles	240,162	(136)
ATVs	985,754	17
Off-Highway Motorcycles	235,883	65

Recreational Marine Standards

EPA efforts at regulating emissions from recreational marine engines are divided into three groups: exhaust emissions from S-I engines, evaporative emissions from SI engines, and diesel engines. These three categories are discussed below.

S-I Exhaust Standards

In October 1996, EPA promulgated emission standards for new S-I gasoline marine engines used in outboards, inboards, and personal watercraft. Options for compliance with this regulation include: conversion to 4-stroke, direct-injection two-stroke, and installing catalytic converters.

EPA's RIA for the final rule contains annualized program costs in each year of program implementation (EPA, 1996). Per unit costs corresponding to fixed and variable costs to the manufacturers were not reported in this RIA. As such, a cost effectiveness value was calculated based on the total annual costs (TACs) reported in the RIA and the reductions for each year of interest. The nationwide annual cost of the regulation is approximately $46.3 million in 2000 and $340 million in 2020. According to the RIA, the VOC emission reduction is expected to reach 538,400 tpy by 2020. The cost per ton values were calculated from these data.

Exhibit 4-5 also shows the emission reductions calculated from the Section 812 emission estimates. These reductions were estimated by summing emissions from affected recreational marine source classification codes (SCCs) for the without-CAAA and with-CAAA scenario for each year, and calculating the difference. In 2010 and 2020, because evaporative emission standards for these same SCCs phase in, it was necessary to estimate the fraction of the total VOC emissions due to exhaust. A rule penetration value was calculated from national level default runs of the NONROAD model for 2010 and 2020, since the inventory only reported VOC emissions in the aggregate (evaporative and exhaust combined). Cost-per ton was applied to these reductions to estimate total costs for each year.

Exhibit 4-5. Yearly Cost per Ton Values for S-I Marine Exhaust Standards

Year	Total Annualized Costs	VOC Reductions (RIA)	Cost (1993 $) per ton	Reductions Calculated from Section 812 Inventory
2000	46,295,786	24,430	1,895	47,448
2010	357,969,394	359,453	996	298,504
2020	340,138,753	538,443	632	368,952

S-I Evaporative Standards

EPA has finalized evaporative HC emission standards for all gasoline-fueled boats (e.g., yachts, sport boats, fishing boats, jet boats, and other types of pleasure craft, including personal watercraft and boats with outboard engines). The evaporative emission standard requires all boats built in 2008 and later to reduce evaporative HC emissions by 80 percent. Manufacturers are expected to meet this standard with a variety of emission-control technologies, including non-permeable fuel tanks and hoses, pressurized fuel tanks with pressure relief valves, insulated tanks, bladder fuel tanks, and volume compensating air bladders.

Increased costs for marine vessels are estimated to be approximately $36 per boat on average. Actual costs may be higher or lower, depending on the size of the engine and the approach the manufacturer uses to meet the standards.[95] Increased costs are partially offset by a discounted lifetime fuel savings of about $27 due to reducing gasoline losses (EPA, 2002b). To place the fuel savings on the same basis as an annualized cost (and not discounted to a net present value), Pechan estimated the annual amount of fuel saved and its associated cost. The estimated lifetime fuel savings was 44 gallons. When annualized over the average lifetime of the vessels (17 years), this translated to net present value fuel savings of approximately $26. As shown in Exhibit 4-6, adjusted per unit costs are estimated by subtracting these fuel savings from the per engine costs, after placing both cost components on a constant 1999 dollars basis. Projected sales in 2010 and 2020 were then multiplied by these per engine costs.

Exhibit 4-6. S-I Marine Evaporative Cost Inputs

Per Unit Cost (2001 $)	Per Unit Cost (1999 $)	2005 Price per Gallon Gasoline (1999 $)	Fuel Savings, (1999$)	Total per Unit (1999 $)	2010 Sales	2020 Sales
36	34.6	2.03	25.81	8.79	678,000	728,000

Compression Ignition (C-I) Recreational Marine Exhaust Standards

In 2002, EPA promulgated regulations to limit VOC, NO_x, CO, and PM from C-I recreational marine engines. These are marine diesel engines over 37 kilowatts (kW) that are used in yachts, cruisers, and other types of pleasure craft. The standards are phased in, beginning in 2006, depending on the size of the engine.

[95] No adjustment for engine costs in future years was cited to account for learning curve effects.

Exhibit 4-7 presents the projected sales and cost data compiled for computing C-I marine costs for the years 2010, and 2020, available from EPA's RIA (EPA, 2002a).

Exhibit 4-7. C-I Recreational Marine Engine Cost Inputs

Year 2010

Affected HP	Engine Sales	Cost per Engine (2001 $)
50-300	15,200	$278
300-750	4,620	$468
>750	517	$1,251

Year 2020

Affected HP	Engine Sales	Cost per Engine (2001 $)
50-300	15,200	$269
300-750	4,620	$345
>750	517	$717

Nonroad Diesel Standards

EPA is regulating NO_x, smoke, VOC, CO, and PM emissions from C-I engines in several phases. EPA finalized the Tier 1 regulation in 1994, Tier 2 and Tier 3 standards in 1998, and more stringent Tier 4 standards in 2004. The C-I Tier engine standards are phased in at various schedules and stringency levels depending on the horsepower of subject C-I engines. The latest Tier 4 diesel engine standards as well as the nonroad diesel sulfur limits described in the next section are referred to as the Clean Air Nonroad Diesel Rule.

Exhibit 4-8 presents the sales and cost per engine data compiled from the relevant regulatory support materials (EPA, 1994; EPA, 1998; EPA, 2004). In the year 2000, only Tier 1 standards were in effect. In 2010, a small number of Tier 2, many Tier 3, and even more Tier 4 engines (for the smallest horsepower ranges) will be manufactured. By 2020, all new engines manufactured will need to meet the Tier 4 engine standards. As such, sales and cost data for only these Tier-level engines were compiled for the relevant years.

Engine and equipment costs of control include variable costs (for incremental hardware costs, assembly costs, and associated markups) and fixed costs (for tooling, R&D, and certification). Operating costs associated with engine use are also included. For the Tier 3 standards, the costs presented represent near-term costs. Note that EPA expects a 20 percent reduction in year 3 and a further 20 percent reduction in year 6 for fixed costs, but these are not reflected in the per engine costs. Tier 4 standards represent near-term costs, and long-term per unit costs that reflect learning curve effects were presented in the RIA, but were not projected to take effect until 2030.

Exhibit 4-8. C-I Nonroad Engine Cost Inputs

Year 2000			
Standard	**Affected HP**	**Engine Sales**	**Cost per engine (1992 $)**
Tier 1 C-I	>50	338,697	$192

Year 2010			
Standard	**Affected HP**	**Engine Sales**	**Cost per engine (1998 $ - Tier 3; 2002 $ - Tier 4)**
Tier 2 C-I	>750	2,286	$80
Tier 3 C-I	50-100	90,454	$282
Tier 3 C-I	100-175	99,371	$658
Tier 3 C-I	175-600	95,814	$872
Tier 3 C-I	600-750	2,676	$2,296
Tier 4 C-I	0-25	160,319	$180
Tier 4 C-I	25-50	168,031	$1,030
Tier 4 C-I	50-75	114,371	$980

Year 2020			
Standard	**Affected HP**	**Engine Sales**	**Cost per engine (2002 $)**
Tier 4 C-I	0-25	201,479	$180
Tier 4 C-I	25-50	203,081	$1,030
Tier 4 C-I	50-75	134,831	$980
Tier 4 C-I	75-100	98,647	$1,660
Tier 4 C-I	100-175	158,761	$2,020
Tier 4 C-I	175-300	90,131	$3,060
Tier 4 C-I	300-600	42,815	$4,420
Tier 4 C-I	600-750	3,700	$8,650
Tier 4 C-I	>750	3,510	$11,280

Sales estimates were not available from EPA's RIA for the number of new Tier 2 and Tier 3 engines sold in 2010. Therefore, Pechan used data from EPA's NONROAD2004 (NR2004) model to estimate the engines sold in 2010. Pechan estimated sales using the following steps:

1. Run NR2004 at the national level using default inputs for 2009 and 2010;
2. Extract in-use population data for all C-I engines, and calculate change in populations from 2009 to 2010. For those technology types and horsepower ranges showing increases between these years, estimate sales as the difference between 2010 and 2009 populations (represents growth as well as engine turnover from lower Tiers),
3. Calculate estimate of turnover within the same Tier, based on scrappage rates for similar sized engines for lower Tiers.
4. Sum the results of step 2 and step 3 to estimate the sales in that year for that class of engines.

Exhibit 4-9 presents the estimated sales by horsepower range. Although Tier 4 sales estimates in 2010 were available from EPA's support documents, Pechan performed this exercise for Tier 4 engines. It was found that the estimated sales based on NR2004 were reasonably close to the projected Tier 4 sales in EPA's RIA (395,000 from NR2004 versus 442,000 in the RIA).

Nonroad Diesel Sulfur Standards

In addition to Tier 4 engine standards, EPA's Clean Air Nonroad Diesel Rule includes a two-step fuel sulfur control program consisting of a sulfur cap of 500 parts per million (ppm) beginning in 2007 to be followed by a nonroad sulfur cap of 15 ppm beginning in 2010 and a locomotive and marine (L&M) sulfur cap of 15 ppm beginning in 2012. In addition to fuel desulfurization costs, the RIA presents estimates of other operating costs – catalyzed diesel particulate filter (CDPF) and closed crankcase ventilation (CCV) maintenance costs, as well as savings due to decreased intervals for oil change maintenance – associated with the final rule (EPA, 2004). The new emission-control technologies are expected to introduce additional operating costs in the form of increased fuel consumption and increased maintenance demands. Operating costs are expressed in terms of cents/gallon of fuel consumed. The cent-per-gallon costs and savings are then combined with projected fuel volumes to generate the aggregate costs of the fuel program in this final rule. A summary of these costs and savings is provided in Exhibit 4-10, which shows the final net costs. These costs are expressed as total annualized costs for the year in question (i.e., not discounted), and were used directly for this analysis.

Exhibit 4-9. Estimated Sales of Tier 2, Tier 3 and Tier 4 Engines in 2010 Nonroad Diesel Rule

Technology Type	HP range	% Turnover in 2010	2009	2010	Growth & Turnover from Lower Tier	Turnover from Existing Tier	Total Sales
Tier 2	>750 <3000	8.25	5,726	7,540	1,814	472	2,286
Tier 3	50-100	5.13	144,213	227,093	82,880	7,397	90,277
Tier 3	100-175	6.68	231,631	316,807	85,176	15,477	100,653
Tier 3	175-600	6.18	286,334	364,773	78,439	17,694	96,133
Tier 3	600-750	8.93	8,883	11,286	2,403	793	3,196
Tier 4	3-75	8.39	654,141	994,366	340,226	54,870	395,096
Data from corresponding size ranges for lower Tiers							
	>750 <3000	8.25	21,954	20,144	-1,810		
	50-100	5.13	1,062,102	1,007,628	-54,475		
	100-175	6.68	946,032	882,819	-63,213		
	175-600	6.18	1,008,007	945,719	-62,288		
	600-750	8.93	21,512	19,591	-1,920		
	3-75	8.39	2,950,804	2,703,286	-247,518		

Exhibit 4-10. C-I Nonroad Diesel Fuel and Operating Cost Inputs

Fuel Costs of Low Sulfur Diesel Fuel

Year	Affected NR 500 ppm (10^6 gallons)	Affected NR 15 ppm (10^6 gallons)	Affected L&M 500 ppm (10^6 gallons)	Affected L&M 15 ppm (10^6 gallons)	Fuel Costs 500 ppm ($ gallons)	Fuel Costs 15 ppm ($ gallons)	NR Fuel Costs 500 ppm (10^6 dollars)	NR Fuel Costs 15 ppm (10^6 dollars)	L&M Fuel Costs 500 ppm (10^6 dollars)	L&M Fuel Costs 15 ppm (10^6 dollars)	NRLM Annual Fuel Costs (10^6 dollars)
2010	4,014	6,189	3,185	0	$0.028	$0.058	$112	$359	$89	-	$561
2020	-	11,578	-	3,024		$0.070	-	$810	-	$212	$1,022

Oil Change Maintenance Savings

Year	Affected NR 500 ppm (10^6 gallons)	Affected NR 15 ppm (10^6 gallons)	Affected L&M 500 ppm (10^6 gallons)	Affected L&M 15 ppm (10^6 gallons)	NR Fuel Savings savings $0.029/gal ($10^6$ dollars)	NR Fuel Savings savings $0.032/gal ($10^6$ dollars)	L&M Fuel Savings savings $0.010/gal ($10^6$ dollars)	L&M Fuel Savings savings $0.011/gal ($10^6$ dollars)	Annual Savings (10^6 dollars)
2010	4,014	6,189	3,185	0	$117	$198	$33	-	$349
2020	-	11,578	-	3,024	-	$371	-	$35	$406

CDPF Maintenance and Regeneration/CCV Maintenance Costs

Year	Fuel Consumed in New CDPF Engines (10^6 gallons)	Annual Costs	Fuel Consumed in CCV Engines (10^6 gallons)	Annual Costs	Total Annual Maintenance Costs
2010	-	0	254	0	0
2020	10,975	156	12,161	18	174

Net Operating Costs

Year	Annual Costs (10^6 dollars)
2010	$212
2020	$790

Notes: All costs expressed as 2002 $.
NR = nonroad
L&M = locomotive and marine
NRLM – nonroad, locomotive, marine

Commercial Marine

EPA has promulgated two sets of commercial marine vessel (CMV) 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 kW 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. In addition to the EPA standards, beginning in 2000, marine diesel engines greater than or equal to 130 kW will be subject to an international NO_x emissions treaty (MARPOL) developed by the International Maritime Organization. Cost information was not available for the international NO_x standards. However, cost and emission reduction information developed in support of the Category 1 and 2 marine diesel engine rulemaking (EPA, 1999b) and the Category 3 marine diesel engine rulemaking (EPA, 2003) is modeled incremental to the MARPOL standards.

EPA expects the costs of compliance with the Category 3 marine standards to be negligible. Because engine manufacturers have been manufacturing engines in compliance with MARPOL Annex VI NO_x standards for the last few years, EPA did not attribute any emission reductions or costs to the EPA rule. While there will be certification and compliance costs, these costs will be negligible, because manufacturers will be able to use the same test data for both programs. Accordingly, EPA did not calculate values to quantify the cost-effectiveness of the final rule. EPA prepared per engine cost estimates for application of the two advanced control technologies: direct water injection and SCR, but these technologies were not part of EPA's rulemaking (EPA, 2003).[96]

Exhibit 4-11 presents total annualized costs in 2010 and 2020 associated with technologies to meet standards specified for Category 1 and 2 vessels (EPA, 1999b). $HC+NO_x$ and PM emission reductions were also reported by EPA, so that the cost per ton of reduced emissions could be computed for 2010 and 2020. These cost per ton values were then applied to reductions calculated from the emissions projections by year. These reductions were estimated by extracting emissions from the affected commercial marine diesel SCCs for the without-CAAA and with-CAAA scenario for each year, and calculating the difference between the scenarios.

Note that EPA regulations affecting emissions from these categories use a completely different categorization scheme than SCCs used in inventory reporting. The two diesel commercial marine SCCs reported in the Section 812 emission inventories include:

- 2280002100 – Marine Vessels, Commercial, Diesel, Port emissions; and
- 2280002200 – Marine Vessels, Commercial, Diesel, Underway emissions.

Consistent with the emission projections analysis, diesel port emissions are assumed to be Category 1 and 2 engines, while diesel underway emissions are assumed to be those from larger Category

[96] Although no cost estimates exist for MARPOL compliance, we can estimate that this omission from our cost estimates is likely to be negligible. EPA (1999) estimates that MARPOL regulations account for roughly 4,000, 43,000, and 77,000 tons of NOx emissions reductions counted in our emissions inventories for 2000, 2010, and 2020, respectively. The incremental cost per ton for additional engine modifications to meet EPA's Tier 2 requirements, however, is modest - between \$50 and \$172 per ton - mainly because these engines tend to be very efficient to control because they have high hours of operation and long useful lives. With a typical increasing marginal cost curve, we would therefore expect cost per ton for meeting the prior MARPOL requirements would be even more cost effective. Even at \$172 per ton, the 77,000 ton reduction in 2020 would yield a total cost of an additional \$13.2 million.

3 engines. Therefore, because the costs for category 3 engines are expected to be negligible, costs were only calculated using reductions from diesel port emissions.

Exhibit 4-11. Commercial Marine Diesel Cost Inputs

Year 2010

	HC + NO_x					PM				
Standard	**Costs in RIA, reflecting learning curve impacts (1997 $)**	**Costs in RIA, learning curve impacts removed (1997 $)**	**Reductions from RIA**	**$/Ton Reduced (1997 $)**	**Section 812 Inventory Reductions**	**Costs in RIA, reflecting learning curve impacts (1997 $)**	**Costs in RIA, learning curve impacts removed (1997 $)**	**Reductions from RIA**	**$/Ton Reduced (1997 $)**	**Section 812 Inventory Reductions**
Cat 1 CMV	9,200,000	14,375,000	60,500	238		4,600,000	7,187,500	2,500	2,875	
Cat 2 CMV	3,000,000	3,000,000[1]	11,100	270		NA[2]	NA[2]	NA[2]	NA[2]	
Combined Cat 1/Cat 2	12,200,000	17,375,000	71,600	243	42,493	4,600,000	7,187,500	2,500	2,875	2,440

Year 2020

	HC + NO_x					PM				
Standard	**Costs in RIA, reflecting learning curve impacts (1997 $)**	**Costs in RIA, learning curve impacts removed (1997 $)**	**Reductions from RIA**	**$/Ton Reduced (1997 $)**	**Section 812 Inventory Reductions**	**Costs in RIA, reflecting learning curve impacts (1997 $)**	**Costs in RIA, learning curve impacts removed (1997 $)**	**Reductions from RIA**	**$/Ton Reduced (1997 $)**	**Section 812 Inventory Reductions**
Cat 1 CMV	4,300,000	6,718,750	141,000	$48		2,200,000	3,437,500	5,800	593	
Cat 2 CMV	600,000	937,500	41,700	$22		NA[2]	NA[2]	NA[2]	NA[2]	
Combined Cat 1/Cat 2	4,900,000	7,656,250	182,700	$42	121,796	2,200,000	3,437,500	5,800	593	3,152

Notes:

1. Insufficient data are presented in the regulatory impact analysis for the standards to remove learning curve impacts from the costs for Category 2 vessels in 2010. However, because Category 2 vessels make up a fairly small portion of costs in 2010, this is unlikely to have a significant impact on our results.
2. NA = Not applicable

Locomotives

In January 1997, EPA proposed draft Locomotive Emission Standards to control emissions of NO_x, VOC, CO, PM, and smoke from newly manufactured and remanufactured diesel-powered locomotive and locomotive engines. In December 1997, EPA finalized the locomotive emission standards (EPA, 1997a). The locomotive standards are to be implemented in three phases, depending on the manufacture date. When fully phased-in by 2040, EPA estimates that the rule will achieve a 60 percent reduction in NO_x emissions, and a 46 percent reduction in PM emissions.

Options for compliance with this regulation include: retarded injection timing, enhanced air cooling, electronic controls, fuel management and combustion chamber configuration. These standards are not expected to require exhaust gas recirculation, catalytic after treatment, or the use of alternative fuels.

EPA completed a cost analysis for the final locomotive standards which incorporates initial equipment costs; remanufacturing costs; fuel economy costs; and certification, production line and in-use testing costs (EPA, 1997b). EPA estimated the per locomotive cost of the draft rule to range from $70,000 for Tier 0 to $252,000 for Tier 2. Initial equipment costs are assumed to accrue in the first year of service, with remanufacture occurring every six years thereafter. EPA estimated total costs as the sum of all yearly costs from 2000 to 2040. EPA estimated that the total annual program cost is $80 million per year for an overall program cost effectiveness of $163/ton of NO_x abated over the 2005-2040 period (EPA, 1997a).[97] The regulatory support document for the standards does not present TAC estimates for each implementation year; therefore, we used the average annualized cost per ton of NO_x abated across the entire implementation period (i.e., a net present value (NPV) cost effectiveness.) EPA expects that actual costs will be no higher than those presented, and will most likely decrease as manufacturers take advantage of learning curve and economy of scale cost reductions, although no learning curve cost adjustments are included in EPA's regulatory support document for the standards. Exhibit 4-12 shows the cost per ton values and the NO_x reductions computed for all locomotives from the Section 812 2010 and 2020 inventories.

Exhibit 4-12. Locomotive Cost Inputs

Year 2010

Standard	$/Ton NO_x Reduced (2002 $)	Section 812 Inventory Reductions
Locomotive	163	448,223

Year 2020

Standard	$/Ton NO_x Reduced (2002 $)	Section 812 Inventory Reductions
Locomotive	163	571,583

[97] In generating this estimate, EPA assumed that the useful life of a locomotive, expressed in MW-hr, is 7.5 times the rated horsepower of the engine. For example, EPA assumed that a 3,500-hp locomotive would have a useful life of 26,250 MW-hr.

Cost Summary

Exhibit 4-13 summarizes the nonroad engine program costs for 2000, 2010, and 2020 given the unit cost information provided earlier in this chapter. The original references used to derive these unit costs reported information for a variety of year dollars. To perform cost modeling, all cost figures were converted to 1999 dollars.

Exhibit 4-13. Nonroad Engine Program Costs in 2000, 2010, and 2020

Standard	Annual Cost (million 1999 $)		
	2000	2010	2020
Phase 1 Small S-I Handheld Class III	22.6	N/A	N/A
Phase 1 Small S-I Handheld Class IV	6.1	N/A	N/A
Phase 1 Small S-I Handheld Class V	5.3	N/A	N/A
Phase 1 Small S-I Non-handheld Class I	35.0	N/A	N/A
Phase 1 Small S-I Non-handheld Class II	2.5	N/A	N/A
Phase 2 Small S-I Handheld Class III	N/A	42.4	44.2
Phase 2 Small S-I Handheld Class IV	N/A	244.4	251.1
Phase 2 Small S-I Handheld Class V	N/A	16.3	13.2
Phase 2 Small S-I Non-handheld Class I	N/A	49.0	51.3
Phase 2 Small S-I Non-handheld Class II	N/A	-140.2	-146.9
Large S-I	N/A	-208.5	-324.3
Snowmobiles	N/A	-19.1	-31.1
ATVs	N/A	82.0	16.5
Off-Highway Motorcycles	N/A	25.8	14.5
S-I Marine Evaporative	N/A	6.0	6.4
S-I Marine Exhaust	99.6	329.2	258.1
C-I Recreational Marine	N/A	6.7	5.8
Tier 1 Diesel	73.7	N/A	N/A
Tier 2 Diesel	N/A	0.2	N/A
Tier 3 Diesel	N/A	185.5	N/A
Tier 4 Diesel	N/A	295.0	1,313.8
Nonroad Diesel Sulfur	N/A	199.1	742.1
Commercial Marine	N/A	17.8	7.2
Locomotive	N/A	68.6	87.5
Total Control Costs	**244.8**	**1,200.1**	**2,309.4**
Notes: N/A = Not applicable			

Note that costs for Phase 1 Small S-I and Tier 1 Diesel standards are not reported in 2010 and 2020 because more stringent levels of standards replace these lower tier standards, and no new Phase 1 or Tier 1 engines are sold as of 2010. Similarly, Tier 2 and Tier 3 Diesel engines are not sold as of 2020, so no costs are reported for these tiers in 2020.

As indicated in Exhibit 4-13, the S-I Marine Exhaust and Tier 1 Diesel Engine standards were responsible for most of the nonroad costs resulting from the Amendments in 2000 (approximately 70 percent combined). Although the S-I Marine Exhaust standards are expected to represent the largest share of nonroad costs in 2010, the Nonroad Diesel Engine and Sulfur standards and the Phase 2 standards for handheld engines are also expected to make up a significant portion of 2010 nonroad costs. By 2020, the

Nonroad Diesel Engine standards are expected to represent more than half of the nonroad vehicle and fuel costs associated with the Amendments.

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CHAPTER 5 - NON-ELECTRIC GENERATING UNIT POINT SOURCE ANALYSIS

This chapter describes the compliance cost analysis performed for 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. The key CAAA requirements that are covered in this chapter for this sector include VOC RACT, OTC State Model VOC and NO_x rules, the NO_x SIP Call, Title III MACT emission standards, new CTGs, refinery cases and settlements, and measures adopted by areas beyond the above to attain or maintain the 1-hour ozone and PM-10 NAAQS. Measures implemented to meet the 8-hour ozone and $PM_{2.5}$ NAAQS requirements are described separately in Chapter 7.

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 reflects costing of rules consistent with 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.

Major Programs And Analysis Methods

This section describes the most prominent elements of the 1990 CAAA that have affected non-EGU point source emissions and direct compliance costs since the Amendments were passed.

Reasonably Available Control Technology

Point source control measures for VOC include Title I reasonable available control technology (RACT) and control technique guideline (CTG) requirements. Point source Title I RACT and CTG controls are applied in areas depending on ozone nonattainment classification. These controls are required in moderate and above 1-hour ozone nonattainment areas, and throughout the Northeast Ozone Transport Region (OTR).

OTC State Model Rules

The Ozone Transport Commission (OTC) was formed by Congress through the CAAA of 1990 to help coordinate control plans for reducing ground-level ozone in the Northeast and Mid-Atlantic States. Twelve States and the District of Columbia are represented in the OTC. During 2001, the OTC States evaluated available control measures that might be necessary to attain and maintain the 1-hour ozone NAAQS, as well as start reducing remaining 8-hour average ozone levels. As a result of its evaluation, the OTC States adopted several model rules to further reduce VOC and NO_x emissions in the region. The VOC model rules were developed to reduce emissions from consumer products, portable fuel containers, architectural and industrial maintenance (AIM) coatings, mobile equipment refinishing and repair operations, and solvent cleaning operations. The NO_x model rule has the potential to reduce emissions from stationary internal combustion engines, gas turbines, industrial boilers, and cement kilns. This NO_x model rule will yield additional reductions for smaller NO_x sources that are not covered under current regional NO_x programs.

The cost of complying with each of the individual model rules, which have each been adopted by each of the states within the OTC region in some form, are estimated based on information in the OTC-sponsored analysis (Pechan, 2001). The estimates in the OTC-sponsored analyses are all on a cost per ton basis, and their development is described in detail in the referenced report. For the cost estimates presented here, the relevant cost per ton values, by model rule, are applied to the relevant emissions reductions estimated in that state and for that model rule, relative to the without CAAA case emissions. Note that the emissions reductions take into account detailed information, collected from Regional Planning Organizations (RPOs) about the implementation and specific market penetration of model rules in individual states within the OTC region. The product of the emissions reduction and cost per ton values yield the estimate of incremental compliance costs.

NO_x SIP Call

For non-EGUs, the NO_x SIP Call affects emissions from industrial, commercial and institutional boilers, gas turbines, cement kilns, and reciprocating internal combustion engines. The affected states have discretion about how to implement regulations to achieve the required emission reductions, so there are state-by-state differences in how each source category is regulated. The cost analysis uses the expected emission reductions by source (from 2002 to 2010 and 2002 to 2020) to determine the control technique that is likely to be used in each case to meet the emission reduction requirements. The cost estimates for the non-EGU source SIP Call sources were developed using the AirControlNET model. The estimated NO_x emission reductions (or control factors) were matched with the most cost effective control measures that had a control efficiency near the needed emission reduction. Then AirControlNET cost equations, or a default cost per ton for the control technology, were multiplied by the expected emission change to estimate the annual cost of compliance. Generally, the available AirControlNET control measures had NO_x control efficiencies within 10 percent of the needed emission reduction.

The estimated NO_x SIP Call compliance costs are shown in Exhibit 5-1 for 2010 and 2020. The estimated costs are $116 million in 2010 and $118 million in 2020. These cost estimates are considerably below the costs estimated in the First Prospective analysis, which applied a more extensive set of NO_x controls to the entire 38 state Ozone Transport Assessment Group (OTAG) region, but they are comparable to the costs estimated by EPA in the NO_x SIP Call Regulatory Impact Analysis (RIA). The September 1998 version of the NO_x SIP Call RIA had non-EGU cost estimates totaling $277 million (in 1990 dollars) for industrial boilers/turbines, IC engines, and cement manufacturing (EPA, 1998). A major difference is that the scenario analyzed in the First Prospective, which was developed prior the rule being finalized and based on information available at the time, applied to a larger geographic area than was covered in the final rule. In addition, since the First Prospective estimate was developed, some of the cost equations have changed that have resulted in a lower cost estimates for certain NO_x control technologies (for IC engine low emission combustion controls, for example).

Exhibit 5-1. NO_x SIP Call Cost Summary by State

State	Annual Cost in 2010 (million 1999$)	Annual Cost in 2020 (million 1999$)	Avg. $/ton
Alabama	13.0	13.3	678
Connecticut	1.2	1.3	1,406
Delaware	3.0	3.1	1,267
DC	0.2	0.2	1,564
Georgia	0.7	0.8	858
Illinois	3.3	3.2	971
Indiana	3.1	3.3	545
Kentucky	1.1	1.2	669
Maryland	5.3	5.5	1,084
Massachusetts	5.8	6.2	1,404
Michigan	2.3	2.3	644
New Jersey	1.8	2.0	1,073
New York	12.5	12.4	1,179
North Carolina	7.7	7.9	980
Ohio	5.4	5.1	845
Pennsylvania	16.7	16.4	1,123
Rhode Island	0.7	0.8	1,636
South Carolina	1.7	1.9	734
Tennessee	11.8	11.6	1,087
Virginia	9.8	10.5	921
West Virginia	9.1	9.3	824
TOTAL	**116.4**	**118.2**	

MACT Standards

Exhibits 5-2 and 5-3 display EPA cost estimates for promulgated MACT standards by MACT bin (e.g., 2-year, 4-year, etc.) (Schaefer, 2006). Total capital, total annual (annualized capital plus operating and maintenance costs), and monitoring, recordkeeping, and reporting (MRR) are presented based on the sum of the existing and new source cost estimates provided by EPA. These tables also identify compliance dates and the cost year. In cases where the cost year was not provided by EPA, the Project Team estimated the year based on the average relationship between the cost year and compliance year for the MACT standards within each bin. For 4-year and 7-year MACT standards, the team assumed the cost year was 5 years before the year of compliance; for 10-year MACT standards, the team assumed the cost year was 8 years before the year of compliance.

Because this study employs a 5 percent discount rate for annualizing capital investments, it was necessary to determine the discount rates used by EPA in developing total annual costs. A review of the five MACT standards with the largest capital costs indicated that EPA used both 7 and 10 percent discount rates in annualizing capital costs. A Government Accountability Office (GAO) report on EPA Regulatory Impact Analyses notes that the difference in assumed discount rates may be due to use of different guidance from the Office of Management and Budget (OMB): "Under Executive Order 12291, OMB's preferred real discount rate was 10 percent. In its January 1996 guidance for Executive Order 12866, OMB has lowered its preferred rate to 7 percent" (GAO, 1997). Given that nearly all 2-year and 4-year MACT standards have a pre-1996 cost year, and nearly all 7 and 10-year MACTs have a cost year of 1996 or later, the Project Team assumed that a 10 percent discount rate was used by EPA in annualizing capital costs for the 2- and 4-year MACT standards and a 7 percent rate was used for all other MACT standards.

It was also necessary to identify the number of years for which capital costs are annualized. The review of sample MACT standards indicated that various years were used, with the time-frame dependent on the estimated life of the capital equipment (e.g., 15 years for flares). Because the review of the sample MACT standards indicated that equipment lives varied between 10 and 20 years, the Project Team chose to assume that each MACT standard's annualized costs reflected an equipment life of 15 years.

The Project Team then subtracted estimated annualized capital costs from the total annual costs assuming a 15 year equipment life and either a 7 or 10 percent discount rate. [98] Next, capital costs were re-annualized using a 5 percent discount rate and a 15 year equipment life, and added to the remaining annual costs to yield the 5 percent discount rate-based total annual costs.

Exhibits 5-2 and 5-3 report two sets of total annual cost estimates – the original estimates reported in EPA's regulatory database, and estimates that adjust the annual costs to reflect use of a 5 percent discount rate. The final four columns in each table present the cost estimates in 1999 prices. These estimates were calculated by multiplying the EPA's original cost estimates by the appropriate GDP price index as discussed in Chapter 1.

Exhibit 5-4 reports the MACT standard cost estimates in 1999 prices for each analysis year. Because 2002 emissions data are used to reflect year 2000 CAAA-scenario emissions, the year 2000 estimates in this table include costs for all MACT standards with compliance dates of 2002 or earlier. Throughout the Second Prospective study, we have used the 2002 NEI as the basis for estimating the year 2000 target analysis year results. The choice of rules to include in the 2000 target year cost analysis is therefore designed to keep the costs and emissions/benefits analyses consistent in scope.

[98] For the five MACT standards with the largest total capital cost, the Project Team used the equipment life and discount rate information reported in the regulatory background documents for this calculation.

Exhibit 5-2. Original and Adjusted Cost Estimates for MACT Standards Included in 2000 Year Baseline

			Costs in millions of cost year $				Costs in millions of 1999$			
Source Category	Compliance Date	Cost Year	Capital	Orig Total Annual	5% Total Annual	MRR	Capital	Orig Total Annual	5% Total Annual	MRR
2-Year										
Dry Cleaning-Perchloroethylene	09/23/96	1996	35.0	3.9	2.7	1.3	36.5	4.1	2.8	1.3
Hazardous Organic NESHAP (SOCMI)	05/14/01	1989	450.0	230.0	214.2	70.0	560.6	286.5	266.8	87.2
4-Year										
Aerospace Industry (surface coating)	09/01/98	1990	30.0	21.0	19.9	0.0	36.0	25.2	23.9	0.0
Chromium Electroplating	01/25/97	1988	45.0	22.0	20.4	11.6	58.2	28.4	26.4	15.0
Coke Ovens	01/01/98	1998	444.0	84.0	68.4	0.0	450.4	85.2	69.4	0.0
Commercial Sterilizers	12/06/98	1987	49.0	6.6	4.9	0.0	65.5	8.8	6.5	0.0
Gasoline Distribution-Stage I	12/15/97	1990	116.7	15.5	11.4	2.4	140.0	18.6	13.7	2.8
Halogenated Solvent Degreasing	12/02/97	1991	0.0	-19.0	-19.0	11.6	0.0	-22.0	-22.0	13.4
Industrial Cooling Towers	03/08/95	1998	2.4	15.2	15.1	0.0	2.4	15.4	15.3	0.0
Magnetic Tape (surface coating)	12/15/97	1992	5.7	1.2	1.0	0.2	6.5	1.3	1.1	0.2
Marine Vessel Loading Operations	09/19/99	1994*	440.0	100.0	83.6	0.0	477.1	108.4	90.7	0.0
Off-Site Waste and Recovery Operations	02/01/00	1995*	42.0	18.0	16.5	0.0	44.6	19.1	17.6	0.0
Petroleum Refineries-Other Sources Not Distinctly Listed	08/18/98	1998	163.0	47.3	41.6	10.1	165.4	48.0	42.2	10.2
Printing/Publishing (Surface Coating)	05/30/99	1994*	0.0	40.0	40.0	0.0	0.0	43.4	43.4	0.0
Polymers & Resins Group I	07/31/97	1989	26.0	18.4	17.5	0.0	32.4	22.9	21.8	0.0
Polymers & Resins Group II	03/03/98	1993*	0.9	0.7	0.6	0.0	1.0	0.7	0.7	0.0
Polymers & Resins Group IV	07/31/97	1989	17.2	-1.9	-2.5	0.0	21.4	-2.4	-3.1	0.0
Secondary Lead Smelters	06/23/97	1992*	4.0	2.8	2.7	0.9	4.5	3.2	3.0	1.1
Shipbuilding and Ship Repair	12/16/96	1991*	0.0	2.0	2.0	0.9	0.0	2.3	2.3	1.1
Wood Furniture (surface coating)	11/21/97	1992*	7.0	15.3	15.1	0.0	7.9	17.3	17.1	0.0
7-Year										
Acetal Resins	06/29/02	1997*	0.0	0.4	0.4	0.0	0.0	0.4	0.4	0.0
Acrylic/Modacrylic Fibers	06/29/02	1997*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ferroalloys Production	05/20/01	1996*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flexible Polyurethane Foam Production	10/08/01	1994	74.0	8.1	7.1	0.0	80.2	8.8	7.7	0.0
Hydrogen Fluoride	06/29/02	1997*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mineral Wool Production	06/01/02	1997*	2.6	1.4	1.4	0.0	2.7	1.4	1.4	0.0
Oil & Nat Gas Production	06/17/02	1997*	7.2	4.4	4.3	0.0	7.4	4.5	4.4	0.0

Exhibit 5-2 (continued)

Source Category	Compliance Date	Cost Year	Costs in millions of cost year $				Costs in millions of 1999$			
			Capital	Orig Total Annual	5% Total Annual	MRR	Capital	Orig Total Annual	5% Total Annual	MRR
Pharmaceuticals Production	09/21/01	1998	139.3	75.0	73.1	0.0	141.3	76.1	74.2	0.0
Phosphoric Acid and Phosphate Fertilizers	06/10/02	1997*	1.4	0.9	0.8	0.0	1.4	0.9	0.9	0.0
Polycarbonates Production (Generic MACT)	06/29/02	1997*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Polyether Polyols Production	06/01/02	1996	10.2	7.7	7.6	0.0	10.6	8.0	7.9	0.0
Portland Cement Manufacturing	06/10/02	1997*	200.0	70.0	67.3	0.0	205.1	71.8	69.0	0.0
Primary Aluminum	10/07/99	1994*	160.0	40.0	37.8	4.0	173.5	43.4	41.0	4.3
Primary Lead Smelting	05/04/01	1996*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pulp & Paper (non-combust) MACT I and (non-chem) MACT III	04/15/98	1995	755.0	172.0	146.4	0.0	802.2	182.8	155.5	0.0
Steel Pickling-HCL Process	06/22/01	1996*	20.0	4.9	4.6	1.9	20.9	5.1	4.8	2.0
Wool Fiberglass Manufacturing	06/14/02	1997*	19.5	6.3	6.0	0.0	20.0	6.5	6.2	0.0
10-Year										
Nat Gas Transmission & Storage	06/17/02	1994*	0.3	0.3	0.3	0.0	0.3	0.3	0.3	0.0
Total			**3,267.4**	**1,014.3**	**913.2**	**115.0**	**3,576.0**	**1,124.4**	**1,013.3**	**138.6**

NOTES:
* Year estimated
MRR – Monitoring, Recordkeeping, Reporting
MACT standards without cost estimates:
Hazardous Waste Combustion -- 4-yr MACT with cost information reported as blank
Publicly Owned Treatment Works (POTW) -- 7-yr MACT with existing source costs listed as “not quantifiable”
Tetrahydrobenzaldehyde Manufacture -- 7-yr MACT with costs included in Hazardous Organic NESHAP above

Exhibit 5-3. Original and Adjusted Cost Estimates for MACT Standards Not Included in 2000 Year Baseline

Source Category	Compliance Date	Cost Year	Costs in millions of cost year $ Capital	Orig Total Annual	5% Total Annual	MRR	Costs in millions of 1999$ Capital	Orig Total Annual	5% Total Annual	MRR
7-Year										
Pesticide Active Ingredient Production	12/23/03	1998	81.9	44.9	43.8	0.3	83.1	45.5	44.4	0.3
Polymers & Resins III	01/20/03	1998	2.3	3.3	3.3	1.4	2.3	3.3	3.3	1.4
Secondary Aluminum	03/24/03	1994	105.4	76.7	75.3	9.2	114.3	83.2	81.6	10.0
Site Remediation	10/08/06	2001*	18.0	9.0	8.8	0.0	17.2	8.6	8.4	0.0
Solvent Extraction for Vegetable Oil Production	04/12/04	1999*	29.7	12.3	11.9	4.2	29.7	12.3	11.9	4.2
Wet Formed Fiberglass Mat Production	04/11/05	2000*	5.3	1.6	1.5	0.0	5.2	1.6	1.5	0.0
10-Year										
Asphalt Processing and Asphalt Roofing Manufacturing	05/01/06	1999	3.7	2.1	2.1	0.5	3.7	2.1	2.1	0.5
Auto & Light Duty Truck	04/26/07	1999	670.0	154.0	145.0	1.0	670.0	154.0	145.0	1.0
Coke Ovens: Pushing, Quenching, & Battery Stacks	04/14/06	2001	89.5	20.2	19.0	1.4	85.5	19.3	18.2	1.3
Fabric Printing, Coating, & Dyeing	05/29/06	2000	18.8	14.5	14.2	1.4	18.4	14.2	13.9	1.4
Friction Products Manufacturing	10/18/05	2000	1.0	0.1	0.0	0.1	0.9	0.1	0.0	0.1
Integrated Iron & Steel	05/20/06	2001	93.0	16.0	14.7	1.0	88.9	15.3	14.1	1.0
Large Appliances (surface coating)	07/23/05	1997	0.0	1.6	1.6	1.5	0.0	1.7	1.7	1.5
Leather Finishing Operations	02/27/05	1997	5.6	0.4	0.4	0.0	5.7	0.5	0.4	0.0
Lime Manufacturing	01/05/07	1997	28.2	18.0	17.6	0.6	28.9	18.5	18.1	0.6
Manufacturing Nutritional Yeast	05/21/04	1998	0.3	0.7	0.7	0.2	0.3	0.7	0.7	0.2
Metal Can (surface coating)	11/13/06	1997	0.0	58.7	58.7	8.4	0.0	60.2	60.2	8.6
Metal Coil (surface coating)	06/10/05	1997	18.1	7.6	7.4	0.8	18.6	7.8	7.5	0.8
Metal Furniture (surface coating)	05/23/06	1998	0.0	14.8	14.8	10.1	0.0	15.0	15.0	10.2
Misc. Metal Parts and Products	01/02/07	1999*	0.0	57.3	57.3	44.8	0.0	57.3	57.3	44.8
MON	11/10/06	1998	127.0	75.1	73.4	0.8	128.8	76.2	74.5	0.8
Paper and Other Web (surface coating)	12/04/05	1998	222.0	69.0	66.0	3.1	225.2	70.0	67.0	3.2
Petroleum Refineries	04/11/05	1998	213.0	79.0	76.1	20.0	216.1	80.1	77.2	20.3
Plastic Parts (surface coating)	04/19/07	1997	0.8	10.9	10.9	5.4	0.8	11.2	11.2	5.5
Plywood & Composite Wood Products	07/30/07	1999	471.0	140.0	133.1	5.6	471.0	140.0	133.1	5.6
Reciprocating Internal Combustion Engines (RICE) (NESHAP/NSPS)	06/15/07	1998	439.0	248.0	242.1	11.4	445.4	251.6	245.6	11.6
Rubber Tire Manufacturing	07/11/05	1997*	0.0	25.9	25.9	0.0	0.0	26.6	26.6	0.0
Semiconductor Manufacturing	05/22/06	1998*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Stationary Combustion Turbines	03/05/07	1998	0.0	86.0	86.0	0.3	0.0	87.2	87.2	0.3
Taconite Iron Ore Processing	10/30/06	2000	57.0	9.0	8.2	0.9	55.8	8.8	8.1	0.9
Wood Building Products (surface coating) (formerly Flat Wood Paneling Products)	05/28/06	1998*	0.0	22.5	22.5	0.0	0.0	22.8	22.8	0.0
Total			**2,700.5**	**1,279.3**	**1,242.4**	**134.3**	**2,715.8**	**1,295.7**	**1,258.6**	**136.1**

* Year estimated.

Exhibit 5-4. Cost Estimates for MACT Standards by Analysis Year

	2000 (in millions of 1999$)				2010 (in millions of 1999$)				2020 (in millions of 1999$)			
Source Category	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**	**Capital**	**Orig Total Annual**	**5% Total Annual**	**MRR**
2-Year												
Dry Cleaning-Perchloroethylene	36.5	4.1	2.8	1.3	36.5	4.1	2.8	1.3	36.5	4.1	2.8	1.3
Hazardous Organic NESHAP (SOCMI)	560.6	286.5	266.8	87.2	560.6	286.5	266.8	87.2	560.6	286.5	266.8	87.2
4-Year												
Aerospace Industry (surface coating)	36.0	25.2	23.9	0.0	36.0	25.2	23.9	0.0	36.0	25.2	23.9	0.0
Chromium Electroplating	58.2	28.4	26.4	15.0	58.2	28.4	26.4	15.0	58.2	28.4	26.4	15.0
Coke Ovens	450.4	85.2	69.4	0.0	450.4	85.2	69.4	0.0	450.4	85.2	69.4	0.0
Commercial Sterilizers	65.5	8.8	6.5	0.0	65.5	8.8	6.5	0.0	65.5	8.8	6.5	0.0
Gasoline Distribution-Stage I	140.0	18.6	13.7	2.8	140.0	18.6	13.7	2.8	140.0	18.6	13.7	2.8
Halogenated Solvent Degreasing	0.0	-22.0	-22.0	13.4	0.0	-22.0	-22.0	13.4	0.0	-22.0	-22.0	13.4
Industrial Cooling Towers	2.4	15.4	15.3	0.0	2.4	15.4	15.3	0.0	2.4	15.4	15.3	0.0
Magnetic Tape (surface coating)	6.5	1.3	1.1	0.2	6.5	1.3	1.1	0.2	6.5	1.3	1.1	0.2
Marine Vessel Loading Operations	477.1	108.4	90.7	0.0	477.1	108.4	90.7	0.0	477.1	108.4	90.7	0.0
Off-Site Waste and Recovery Operations	44.6	19.1	17.6	0.0	44.6	19.1	17.6	0.0	44.6	19.1	17.6	0.0
Petroleum Refineries-Other Sources Not Distinctly Listed	165.4	48.0	42.2	10.2	165.4	48.0	42.2	10.2	165.4	48.0	42.2	10.2
Printing/Publishing (Surface Coating)	0.0	43.4	43.4	0.0	0.0	43.4	43.4	0.0	0.0	43.4	43.4	0.0
Polymers & Resins Group I	32.4	22.9	21.8	0.0	32.4	22.9	21.8	0.0	32.4	22.9	21.8	0.0
Polymers & Resins Group II	1.0	0.7	0.7	0.0	1.0	0.7	0.7	0.0	1.0	0.7	0.7	0.0
Polymers & Resins Group IV	21.4	-2.4	-3.1	0.0	21.4	-2.4	-3.1	0.0	21.4	-2.4	-3.1	0.0
Secondary Lead Smelters	4.5	3.2	3.0	1.1	4.5	3.2	3.0	1.1	4.5	3.2	3.0	1.1
Shipbuilding and Ship Repair	0.0	2.3	2.3	1.1	0.0	2.3	2.3	1.1	0.0	2.3	2.3	1.1
Wood Furniture (surface coating)	7.9	17.3	17.1	0.0	7.9	17.3	17.1	0.0	7.9	17.3	17.1	0.0
7-Year in 2000 Baseline												
Acetal Resins	0.0	0.4	0.4	0.0	0.0	0.4	0.4	0.0	0.0	0.4	0.4	0.0
Acrylic/Modacrylic Fibers	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ferroalloys Production	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flexible Polyurethane Foam Production	80.2	8.8	7.7	0.0	80.2	8.8	7.7	0.0	80.2	8.8	7.7	0.0
Hydrogen Fluoride	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mineral Wool Production	2.7	1.4	1.4	0.0	2.7	1.4	1.4	0.0	2.7	1.4	1.4	0.0
Oil & Nat Gas Production	7.4	4.5	4.4	0.0	7.4	4.5	4.4	0.0	7.4	4.5	4.4	0.0
Pharmaceuticals Production	141.3	76.1	74.2	0.0	141.3	76.1	74.2	0.0	141.3	76.1	74.2	0.0
Phosphoric Acid and Phosphate Fertilizers	1.4	0.9	0.9	0.0	1.4	0.9	0.9	0.0	1.4	0.9	0.9	0.0
Polycarbonates Production (Generic MACT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Polyether Polyols Production	10.6	8.0	7.9	0.0	10.6	8.0	7.9	0.0	10.6	8.0	7.9	0.0
Portland Cement Manufacturing	205.1	71.8	69.0	0.0	205.1	71.8	69.0	0.0	205.1	71.8	69.0	0.0
Primary Aluminum	173.5	43.4	41.0	4.3	173.5	43.4	41.0	4.3	173.5	43.4	41.0	4.3
Primary Lead Smelting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pulp & Paper (non-combust) MACT I and (non-chem) MACT III	802.2	182.8	155.5	0.0	802.2	182.8	155.5	0.0	802.2	182.8	155.5	0.0
Steel Pickling-HCL Process	20.9	5.1	4.8	2.0	20.9	5.1	4.8	2.0	20.9	5.1	4.8	2.0
Wool Fiberglass Manufacturing	20.0	6.5	6.2	0.0	20.0	6.5	6.2	0.0	20.0	6.5	6.2	0.0
7-Year Not in 2000 Baseline												
Pesticide Active Ingredient Production					83.1	45.5	44.4	0.3	83.1	45.5	44.4	0.3
Polymers & Resins III					2.3	3.3	3.3	1.4	2.3	3.3	3.3	1.4

Source Category	2000 (in millions of 1999$) Capital	2000 Orig Total Annual	2000 5% Total Annual	2000 MRR	2010 (in millions of 1999$) Capital	2010 Orig Total Annual	2010 5% Total Annual	2010 MRR	2020 (in millions of 1999$) Capital	2020 Orig Total Annual	2020 5% Total Annual	2020 MRR
Secondary Aluminum					114.3	83.2	81.6	10.0	114.3	83.2	81.6	10.0
Site Remediation					17.2	8.6	8.4	0.0	17.2	8.6	8.4	0.0
Solvent Extraction for Vegetable Oil Production					29.7	12.3	11.9	4.2	29.7	12.3	11.9	4.2
Wet Formed Fiberglass Mat Production					5.2	1.6	1.5	0.0	5.2	1.6	1.5	0.0
10 Year in 2000 Baseline												
Nat Gas Transmission & Storage	0.3	0.3	0.3	0.0	0.3	0.3	0.3	0.0	0.3	0.3	0.3	0.0
10 Year Not in 2000 Baseline												
Asphalt Processing and Asphalt Roofing Manufacturing					3.7	2.1	2.1	0.5	3.7	2.1	2.1	0.5
Auto & Light Duty Truck					670	154	145	1	670	154	145	1
Coke Ovens: Pushing, Quenching, & Battery Stacks					85.5	19.3	18.2	1.3	85.5	19.3	18.2	1.3
Fabric Printing, Coating, & Dyeing					18.4	14.2	13.9	1.4	18.4	14.2	13.9	1.4
Friction Products Manufacturing					0.9	0.1	0	0.1	0.9	0.1	0	0.1
Integrated Iron & Steel					88.9	15.3	14.1	1	88.9	15.3	14.1	1
Large Appliances (surface coating)					0	1.7	1.7	1.5	0	1.7	1.7	1.5
Leather Finishing Operations					5.7	0.5	0.4	0	5.7	0.5	0.4	0
Lime Manufacturing					28.9	18.5	18.1	0.6	28.9	18.5	18.1	0.6
Manufacturing Nutritional Yeast					0.3	0.7	0.7	0.2	0.3	0.7	0.7	0.2
Metal Can (surface coating)					0	60.2	60.2	8.6	0	60.2	60.2	8.6
Metal Coil (surface coating)					18.6	7.8	7.5	0.8	18.6	7.8	7.5	0.8
Metal Furniture (surface coating)					0	15	15	10.2	0	15	15	10.2
Misc. Metal Parts and Products					0	57.3	57.3	44.8	0	57.3	57.3	44.8
MON					128.8	76.2	74.5	0.8	128.8	76.2	74.5	0.8
Paper and Other Web (surface coating)					225.2	70	67	3.2	225.2	70	67	3.2
Petroleum Refineries					216.1	80.1	77.2	20.3	216.1	80.1	77.2	20.3
Plastic Parts (surface coating)					0.8	11.2	11.2	5.5	0.8	11.2	11.2	5.5
Plywood & Composite Wood Products					471	140	133.1	5.6	471	140	133.1	5.6
Reciprocating Internal Combustion Engines (RICE) (NESHAP/NSPS)					445.4	251.6	245.6	11.6	445.4	251.6	245.6	11.6
Rubber Tire Manufacturing					0	26.6	26.6	0	0	26.6	26.6	0
Semiconductor Manufacturing					0	0	0	0	0	0	0	0
Stationary Combustion Turbines					0	87.2	87.2	0.3	0	87.2	87.2	0.3
Taconite Iron Ore Processing					55.8	8.8	8.1	0.9	55.8	8.8	8.1	0.9
Wood Building Products (surface coating) (formerly Flat Wood Paneling Products)					0	22.8	22.8	0	0	22.8	22.8	0
Total	**3,576.0**	**1,124.4**	**1,013.3**	**138.6**	**6,291.8**	**2,420.1**	**2,271.9**	**274.7**	**6,291.8**	**2,420.1**	**2,271.9**	**274.7**

MACT Standards without cost information:
Hazardous Waste Combustion -- 4-yr MACT with cost information reported as blank
Publicly Owned Treatment Works (POTW) -- 7-yr MACT with existing source costs listed as “not quantifiable”
Tetrahydrobenzaldehyde Manufacture -- 7-yr MACT with costs included in Hazardous Organic NESHAP

New Control Technique Guidelines

In section 183 of the CAAA of 1990, EPA was required to issue control techniques guidelines for 11 categories of stationary sources of VOC emissions for which such guidelines had not been issued previously. These new CTGs were required to be issued within 3 years of enactment. Although EPA issues no Federal regulations to implement CTGs, they yield emissions reductions through a process that involves state adoption of the guidelines in state regulations to achieve the same or similar emissions reductions. States have flexibility to implement regulations that follow the CTGs exactly, or they may choose to adapt the CTGs using their own analyses. CTGs are typically adopted in states with 1-hour ozone moderate or worse non-attainment areas.

The cost effectiveness values for these CTGs are listed in Exhibit 5-5. The later section in this chapter headed "1-hour ozone SIP measures" explains how these cost effectiveness values were used in this analysis to estimate projection year with CAAA scenario costs by projection year.

Refinery Cases and Settlements

EPA's internal petroleum refinery initiative is an integrated enforcement and compliance strategy to address air emissions from the nation's petroleum refineries. Since March 2000, EPA has entered into 17 settlements with U.S. companies that refine nearly 77 percent of the nation's petroleum refinery capacity. These settlements cover 85 refineries in 25 states, and on full implementation will result in annual emission reductions of about 80 thousand NO_x tons per year (tpy) and 235 thousand annual SO_2 tons (EPA, 2006). Settling companies have agreed to invest more than $4.4 billion in control technologies and pay civil penalties of $55 million. They will also perform supplemental environmental projects valued at approximately $63 million.

The effects of these emission reductions have been included in the 2010 and 2020 emission projections - for consistency, we therefore estimate the costs. These emissions reductions typically apply at refineries that would not otherwise be affected by CAAA regulations; the settlements typically apply because a facility has violated New Source Review (NSR) requirements that were in place prior to the CAAA. In addition, they apply to emissions of criteria pollutants not typically addressed through MACT requirements that apply at petroleum refineries. As a result, these emissions should be, but are not, reflected in the with CAAA scenario (based on the 2002 NEI, which reflects actual emissions in 2002). They are implemented in this analysis as adjustment to the NEI which implies additional costs beyond those for CAAA regulations estimated elsewhere.

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

1. Fluid Catalytic Cracking Units (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 variation on this theme by 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 scrubbers

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

2. Heaters/Boilers

Control requirements apply to heaters and boilers 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/hour separately, but the requirements do not appear to be different from what is required for 40-100 mmBtu. 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 discretion in disclosing which individual heaters/boilers to control, as well as the control techniques to apply.

Although information on specific settlements is not always available, particularly on an annual cost basis, we estimated direct compliance costs on an annualized per refinery basis using the following steps:

1. The refineries and associated FCCUs that are affected by the settlements were identified in the 2010 and 2020 core scenario point source emission databases.
2. Control costs were estimated for the subset of refineries that had FCCU SO_2 emissions of at least 100 tons per year and existing SO_2 control efficiencies below the level required by the settlement agreements.
3. Control costs were estimated using the AirControlNET control cost equations for applying a wet gas scrubber to achieve 90 percent SO_2 control. This is one of the controls that EPA has required that some refineries install at FCCUs as part of their settlements. Some settlements require that FCCUs reduce emissions via catalyst additives. However, control cost information was not available for catalyst additives. Because cost information was available for wet gas scrubbers, and control levels are similar to those expected for catalyst additives, wet gas scrubbers were estimated to be representative of the compliance costs for controlling all FCCU SO_2 emissions (Eagleson et el., 2004).
4. The average cost effectiveness of applying wet gas scrubbing to FCCUs was estimated based on the costs of applying this control technique to a 25,000 barrel per stream day FCC unit and a 90 percent control efficiency.

Exhibit 5-5 provides estimates of the annualized costs of the refinery settlements in 2010 and 2020 for the states with affected refineries.

Exhibit 5-5. Refinery Settlements - State-Level Cost Summary

State	2010 Annual Cost (million 1999$)	2010 Annualized Capital Cost (million 1999$)	2010 O&M Cost (million 1999$)	2020 Annual Cost (million 1999$)	2020 Annualized Capital Cost (million 1999$)	2020 O&M Cost (million 1999$)
California	4.6	3.3	1.3	6.1	4.4	1.7
Illinois	27.0	19.5	7.4	30.9	22.4	8.5
Indiana	20.1	14.6	5.5	23.0	16.7	6.3
Louisiana*	11.6	8.4	3.2	13.3	9.6	3.7
Minnesota	1.8	1.3	0.5	2.0	1.5	0.6
New Mexico	1.4	1.0	0.4	1.6	1.2	0.5
Ohio	69.3	50.2	19.1	79.4	57.5	21.9
Pennsylvania	45.9	33.3	12.7	52.6	38.1	14.5
Texas	69.0	50.0	19.0	75.4	54.6	20.8
Utah	1.7	1.2	0.5	2.0	1.4	0.5
Washington	2.3	1.6	0.6	2.6	1.9	0.7
U.S.	254.7	184.5	70.2	288.9	209.3	79.6

* One refinery in Louisiana (Conoco Phillips Belle Chasse) was shut down for approximately six months after Hurricane Katrina, but as of March 2006 DOE reports it is once again operating at full capacity. There is no information the Project Team is aware of to suggest that the terms of specific settlements have been altered for this or other Louisiana refineries in response to Katrina-induced damage.

1-Hour Ozone SIP Measures-VOC and NO_x

Title I of the Clean Air Act contains the nonattainment provisions, and it includes a mix of federal measures and state implementation plan (SIP) requirements which are designed to bring each nonattainment area into compliance with the relevant national ambient air quality standards. This section addresses the requirements for bringing areas into attainment of the 1-hour ozone NAAQS. This cost analysis estimates 1-hour ozone NAAQS compliance costs by first estimating the cost of meeting RACT, control technique guideline, and regional VOC control measures. As indicated in Exhibit 5-6 below, two of these measures apply nationally (marine vessel loading and waste management facilities rules), but most of these measures are applied in marginal, moderate, or worse ozone non-attainment areas. In addition, , and throughout the Northeast ozone transport region. Then, the cost of measures that go beyond the above to achieve additional VOC and NO_x emission reductions by nonattainment area are estimated using area- specific information about requirements and the AirControlNET model to estimate the associated control costs. We describe the main elements of this two step estimation process below.

Federal Rule Analysis

Exhibit 5-6 summarizes the non-EGU point source VOC control cost information that was used in the analysis to estimate the cost of national VOC rules, new CTGs, and VOC RACT for non-EGU point source categories. (We present similar control cost inputs for area/nonpoint sources in Chapter 6.) Exhibit 5-6 cost per ton values were developed in the first prospective analysis (EPA, 1999) and are applied here after adjusting from 1990$ to 1999$ using the GDP implicit price deflator.

Results of the analysis of the costs for national VOC rules, new CTGs, and VOC RACT requirements are shown in Exhibit 5-7 (for 2000), Exhibit 5-8 (for 2010), and Exhibit 5-9 (for 2020). These tables include the costs for meeting these Title I requirements for both point and nonpoint sources.

Total cost estimates were developed by multiplying the expected emission reductions (the difference between with- and without-CAAA scenario emissions, derived from the Section 812 emissions inventory - see USEPA 2006) by the cost efficiency ($/ton) values in Exhibit 5-6. The analysis was conducted for each of the affected source categories for each projection year, then aggregated to generate total cost estimates. Most of the emission reductions begin in the years between 1990 and 2000, and continue to be in place throughout the study period.

Exhibit 5-6. Non-EGU Point Source VOC Cost Inputs by Provision

Non-EGU Point Source Provision	$ per ton VOC (1999$)
National Rules	
Marine vessel loading: petroleum liquids	1,600
TSDFs	141
New CTGs (moderate and above)	
Printing – lithographic	-100
SOCMI distillation	454
SOCMI reactor	454
Non-CTG and Group III CTG RACT (moderate and above)	
Automobile surface coating	3,356
Bakeries	1,003
Beverage can surface coating	899
Carbon black manufacture	938
Charcoal manufacturing	1,688
Cold cleaning	1,018
Fabric printing	2,000
Flatwood surface coating	2,969
Leather products	1,250
Metal surface coating	2,969
Organic acids manufacture	1,250
Paint and varnish manufacture	790
Paper surface coating	-153
Plastic parts surface coating	552
Rubber tire manufacture	133
SOCMI reactor: pharmaceutical	1,928
Whiskey fermentation – aging	32
CTG RACT (marginal and above)	
Cellulose acetate manufacture	805
Dry cleaning-stoddard	65
In-line degreasing	-364
Open-top degreasing	-354
Printing-letterpress	113
Terephthalic acid manufacture	830
Vegetable oil manufacture	-64

Note: Negative values in this table result in situations where application of the control technique yields net savings. Net savings can result where the VOC emissions are associated with fugitive feedstock or product emissions - the savings are from conservation of the feedstock or product. In some cases, product substitution may also result in cost savings (e.g., water-based substitute degreasers may be less expensive than VOC-based degreasers).

Exhibit 5-7. 1-Hour Ozone NAAQS Implementation Cost by Provision - 2000

Sector	Provision	Annual Cost (million 1999$)
Area	Architectural & industrial maintenance coating	23.8
Area	Automobile refinishing	10.6
Area	Bulk Terminals	2.3
Area	Consumer solvents	36.2
Area	Dry cleaning – petroleum	12.6
Area	Municipal solid waste landfills	69.4
Area	OTC Mobile MER Rule	20.4
Area	OTC Solvent Cleaning Rule	81.5
Area	Oil and natural gas production fields	27.8
Area	Paper surface coating	0.2
Area	Pharmaceutical manufacture	1.3
Area	Service stations - stage I-truck unloading	33.4
Area	Treatment, storage and disposal facilities	121.4
Non-EGU	Automobile Surface Coating	108.3
Non-EGU	Bakeries	6.8
Non-EGU	Beverage Can Surface Coating	19.0
Non-EGU	Carbon Black Manufacture	2.6
Non-EGU	Cellulose Acetate Manufacture	0.2
Non-EGU	Dry Cleaning – Stoddard	0.1
Non-EGU	Fabric Printing	10.8
Non-EGU	Flatwood Surface Coating	11.9
Non-EGU	In-line Degreasing	(0.3)
Non-EGU	Leather Products	1.5
Non-EGU	Marine Vessel Loading: Petroleum Liquids	57.6
Non-EGU	Metal Surface Coating	120.8
Non-EGU	Municipal Landfills	6.7
Non-EGU	Open Top Degreasing	(1.8)
Non-EGU	Organic Acids Manufacture	0.8
Non-EGU	Paint & Varnish Manufacture	4.2
Non-EGU	Paper Surface Coating	(3.3)
Non-EGU	Plastic Parts Surface Coating	4.1
Non-EGU	Printing – Letterpress	(0.1)
Non-EGU	Printing – Lithographic	(0.3)
Non-EGU	Rubber Tire Manufacture	0.3
Non-EGU	TSDFs	0.5
Non-EGU	Terephthalic Acid Manufacture	0.0
Non-EGU	Vegetable Oil Manufacture	(0.0)
Non-EGU	Whiskey Fermentation - Aging	0.2
	TOTAL	**791.2**

Exhibit 5-8. 1-Hour Ozone NAAQS Implementation Cost By Provision - 2010

Sector	Provision	Annual Cost (million 1999$)
Area	Architectural & industrial maintenance coating	26.1
Area	Automobile refinishing	14.9
Area	Bulk Terminals	2.7
Area	Consumer solvents	39.5
Area	Dry cleaning – petroleum	17.7
Area	Municipal solid waste landfills	81.9
Area	OTC Consumer Products Rule	17.5
Area	OTC Mobile MER Rule	23.6
Area	OTC Solvent Cleaning Rule	117.8
Area	Oil and natural gas production fields	20.8
Area	Paper surface coating	0.2
Area	Pharmaceutical manufacture	1.5
Area	Service stations – stage I-truck unloading	40.1
Area	Treatment, storage and disposal facilities	143.3
Non-EGU	Automobile Surface Coating	131.9
Non-EGU	Bakeries	7.9
Non-EGU	Beverage Can Surface Coating	21.1
Non-EGU	Carbon Black Manufacture	2.6
Non-EGU	Cellulose Acetate Manufacture	0.2
Non-EGU	Dry Cleaning – Stoddard	0.1
Non-EGU	Fabric Printing	9.4
Non-EGU	Flatwood Surface Coating	13.3
Non-EGU	In-line Degreasing	(0.4)
Non-EGU	Leather Products	1.2
Non-EGU	Marine Vessel Loading: Petroleum Liquids	66.7
Non-EGU	Metal Surface Coating	128.9
Non-EGU	Municipal Landfills	9.6
Non-EGU	Open Top Degreasing	(2.5)
Non-EGU	Organic Acids Manufacture	0.8
Non-EGU	Paint & Varnish Manufacture	5.7
Non-EGU	Paper Surface Coating	(3.6)
Non-EGU	Plastic Parts Surface Coating	4.4
Non-EGU	Printing – Letterpress	(0.1)
Non-EGU	Printing – Lithographic	(0.3)
Non-EGU	Rubber Tire Manufacture	0.3
Non-EGU	TSDFs	0.6
Non-EGU	Terephthalic Acid Manufacture	0.0
Non-EGU	Vegetable Oil Manufacture	(0.0)
Non-EGU	Whiskey Fermentation - Aging	0.1
	TOTAL	**945.7**

Exhibit 5-9. 1-Hour Ozone NAAQS Implementation Cost by Provision - 2020

Sector	Provision	Annual Cost (million 1999$)
Area	Architectural & industrial maintenance coating	28.3
Area	Automobile refinishing	20.7
Area	Bulk Terminals	3.2
Area	Consumer solvents	42.8
Area	Dry cleaning – petroleum	24.6
Area	Municipal solid waste landfills	104.9
Area	OTC Consumer Products Rule	18.5
Area	OTC Mobile MER Rule	28.3
Area	OTC Solvent Cleaning Rule	157.6
Area	Oil and natural gas production fields	15.6
Area	Paper surface coating	0.3
Area	Pharmaceutical manufacture	1.9
Area	Service stations - stage I-truck unloading	47.0
Area	Treatment, storage and disposal facilities	183.6
Non-EGU	Automobile Surface Coating	165.0
Non-EGU	Bakeries	9.3
Non-EGU	Beverage Can Surface Coating	25.3
Non-EGU	Carbon Black Manufacture	2.9
Non-EGU	Cellulose Acetate Manufacture	0.2
Non-EGU	Dry Cleaning – Stoddard	0.2
Non-EGU	Fabric Printing	8.6
Non-EGU	Flatwood Surface Coating	16.2
Non-EGU	In-line Degreasing	(0.5)
Non-EGU	Leather Products	1.0
Non-EGU	Marine Vessel Loading: Petroleum Liquids	76.5
Non-EGU	Metal Surface Coating	151.7
Non-EGU	Municipal Landfills	13.3
Non-EGU	Open Top Degreasing	(3.5)
Non-EGU	Organic Acids Manufacture	0.9
Non-EGU	Paint & Varnish Manufacture	7.9
Non-EGU	Paper Surface Coating	(4.1)
Non-EGU	Plastic Parts Surface Coating	4.8
Non-EGU	Printing – Letterpress	(0.1)
Non-EGU	Printing – Lithographic	(0.3)
Non-EGU	Rubber Tire Manufacture	0.4
Non-EGU	TSDFs	0.7
Non-EGU	Terephthalic Acid Manufacture	0.0
Non-EGU	Vegetable Oil Manufacture	(0.0)
Non-EGU	Whiskey Fermentation – Aging	0.1
	TOTAL	**1,153.8**

Exhibits 5-7 through 5-9 show that the estimated cost of these VOC regulations is close to $800 million in 2000, increasing to almost $1 billion by 2010, and to $1.15 billion in 2020. Source categories with more than $100 million in estimated compliance costs in 2000 include hazardous waste treatment, storage and disposal facilities (TSDFs), automobile surface coating (at auto assembly plants), and metal surface coating. While the magnitude of the estimated compliance costs increases somewhat from 2000 to 2010, the distribution remains nearly the same, with the exception that the OTC model rules are added, with the OTC solvent cleaning rule being among the most costly in 2010. The OTC solvent cleaning rule has an estimated $110 million compliance cost in that year. Results for 2020 are similar to those in 2010. By 2020, municipal solid waste landfills have a compliance cost above $100 million.

Air ControlNET-Based Analyses

AirControlNET's Least Cost Module was used to estimate additional non-EGU and area source control costs for the 1-hr ozone standard that are not captured elsewhere. In this analysis, the Least Cost Module inputs were 2002 annual NO_x and VOC reduction targets by nonattainment area and the nonattainment area county specifications. The targets were derived from our research of adopted rules implemented in SIPs for non-attainment areas not among the eastern states affected by the NOx SIP call or Ozone Transport Region model rules. Our research for these areas is reported in detail in Chapter 3 of the accompanying Second Prospective emissions report. The results of the cost analysis for these additional measures are summarized by area in Exhibit 5-10. Analysis for two of the areas including in Exhibit 5-10 - the Bay Area Air Quality Management District in northern California, and the South Coast Air Quality Management District in southern California - is described in greater detail in the next section and in Appendix D.

The 1-hour ozone NAAQS cost analysis for the nonattainment areas in Texas and Louisiana with NO_x emissions caps takes the total point source NO_x emission reductions that are needed from 2002 NO_x emission levels and applies an emissions cap, or an emission reduction target in order to meet the emission cap. In the Houston-Galveston-Brazoria (HGB) area, the NO_x cap attempts to achieve an 80 percent reduction in certain point source NO_x emitters from a 1999 baseline. This reduction is modeled in the section 812 study as a 55 percent reduction from 2002 emissions from non-EGU point sources.

In total, AirControlNET applies non-EGU point source control measures to the HGB area to reduce 43,000 tons per year of NO_x emissions. These reductions are achieved at an average cost of $6,000 per ton. However, the marginal cost of the last ton reduced is about $12,500 per ton. The most expensive controls simulated are applying low NO_x burners plus selective catalytic reduction (SCR) to the process heaters at the petrochemical facilities in the HGB area.

Similar analyses are performed to estimate the NO_x program control costs associated with the 1-hour ozone SIPs for the Beaumont-Port Arthur and Dallas-Ft. Worth areas in Texas, and the Baton Rouge, LA area. The control regions are the same as the 1-hour ozone nonattainment area definition in the two Texas areas. The Baton Rouge emissions cap applies to a nine parish control region in and around the nonattainment area.

The 1-hour ozone cost estimates for the California nonattainment areas focuses on the source categories with expected VOC and NO_x emission changes resulting from regulations that influence emissions in the period between 1999 and 2010. As is noted in the companion emissions analysis report, the ARB provided a control factor file by source category and air pollution control district that was applied to estimate emission changes via regulation during this period. The source classification codes for these affected source categories were matched with control measures in AirControlNET to estimate the costs associated with meeting the regulations by nonattainment area.

Exhibit 5-10. 1-Hour Ozone Non-EGU Point Source Control Cost

Nonattainment Area	Emission Reduction Target (tons)		Available AirControlNET Reductions (tons)		Annual Cost (million 1999$)	
	NO_x	VOC	NO_x	VOC	NO_x	VOC
Baton Rouge	25,448	-	27,948	-	$17	$-
Beaumont-Port Arthur	7,187	-	8,688	-	6	-
Dallas-Fort Worth	199	-	239	-	0	-
Houston Galveston Area	62,210	-	43,095	-	266	-
Los Angeles-South Coast	1,194	5,563	1,565	418	1	5
Monterey Bay	-	-	-	-	-	0
Sacramento Metro	6	84	17	25	0	0
San Diego	-	31	-	68	-	1
San Francisco-Bay Area	8,524	372	9,796	388	13	5
San Joaquin Valley	3,859	71	3,975	83	1	1
San Joaquin Valley-Merced	10	-	45	-	0	-
Santa Barbara-Santa Maria	758	659	999	-	0	-
Southeast Desert Modified	459	809	536	100	0	1
Ventura Co CA	9	6	17	-	0	-
TOTALS					$304	$13

The ability of AirControlNET to correctly simulate the compliance strategy and cost of meeting the emission requirements for a source category is related to whether the model has control measures for each source category that are representative of how the source will actually comply. For example, for VOC emitting point sources in the South Coast Air Basin, AirControlNET estimates that coating operations will need to build total permanent enclosures around each major VOC emission source. This control technique can cost upwards of $10,000 per ton in some situations.

California Nonattainment Area SIP-Based Analyses

As a supplement to the 1-hour ozone cost analysis described previously in this chapter, historical information from the 1-hour ozone SIPs from two of the prominent ozone nonattainment areas in California - the Bay Area and the South Coast Air Basin were evaluated. This information allowed us to develop an independent estimate of the costs to meet the 1-hour ozone NAAQS for these areas and to improve upon the estimates made using AirControlNET. This analysis is described in Appendix D and summarized below.

For the Bay Area, the 2005 Ozone Strategy describes how the Bay Area will fulfill California Clean Air Act planning requirements through the proposed control strategy. The control strategy includes stationary source control measures to be implemented through Air District regulations; mobile source control measures to be implemented through incentive programs and other activities; and transportation control measures to be implemented through incentive programs in cooperation with the Metropolitan Transportation Commission, local governments, transit agencies, and others.

The estimated annual cost of the Bay Area stationary and area source control measures to meet the 1-hour ozone NAAQS is $286 million in 1999 dollars. This cost estimate is based on control measures that have estimated dollar per ton estimates in the BAAQMD clean air plans. This cost estimate could be somewhat higher if the cost of measures which had no dollar per ton estimates provided in

BAAQMD reports were included, assuming that most of these measures are unlikely to be cost-saving in nature.

The 1997 South Coast Air Quality Management District (SCAQMD) plan for attaining the 1-hour ozone NAAQS for the South Coast Air Basin was used to estimate the cost of stationary and area source control measures adopted in the SCAB since the 1990 CAAA (SCAQMD, 1996). The estimated annual cost of the ozone precursor control measures adopted in this time period is estimated to be $219 million (1999 dollars). This represents the cost of the point and area source control measures with cost per ton values provided in the SCAQMD plan documents. This expenditure is expected to provide combined reactive organic gas (ROG) plus NO_x emission reductions of 123.1 tons per day, of 44,931 tons per year. Therefore, the combined ROG plus NO_x cost effectiveness is $4,870 per ton.

Exhibit 5-10 shows the estimated cost for the ozone NAAQS compliance measures implemented by the ozone nonattainment areas in Texas and California (those outside of the NO_x SIP Call area). The columns labeled emission reduction target provide the estimated emission amounts that need to be reduced to either meet the NO_x emissions cap (in Louisiana and Texas areas) or the emissions that are estimated to be reduced via regulation (in total) in the air districts in California.

Houston-Galveston-Brazoria Area Highly Reactive VOC Rules Analyses

A significant feature of the Houston-Galveston area 1-hour ozone SIP is the initiation of control programs to reduce highly reactive VOC (HRVOC) emissions at petroleum refineries and chemical plants in the nonattainment area. This cost analysis estimates the costs of applying controls to three HRVOC source types in this area: flares, fugitive VOC emissions, and cooling towers. In addition to the AirControlNET-based analysis of the costs of meeting the NO_x emissions cap in the HGB area, a separate assessment was performed of the costs of meeting the recent fugitive VOC emission limits that have been included in the 1-hour ozone SIP, and is described below.

Vent gas streams at petroleum refineries, natural gas processing and petrochemical processes that have the potential to emit highly reactive VOCs in the Houston-Galveston area are subject to certain VOC emission monitoring and control requirements. This rule establishes a set pounds per hour emission rate for all highly reactive VOCs emitted from each flare at a facility. In order to estimate the costs of this flare control requirement at HGB area facilities, the 2002 emission inventory for this nonattainment area was used to establish the cost of controlling a single flare based on cost estimates developed by the Texas Commission on Environmental Quality (TCEQ) and information from the EPA OAQPS Control Cost Manual for flares (which provided a breakdown between capital and operating costs). Based on data from the EPA cases and settlements that indicated that each refinery has on average three flares per facility, the per flare control costs were applied to the affected facilities in the HGB ozone nonattainment area to estimate the total annualized costs of this regulation in 2010 and 2020. The resulting cost estimate was $6.3 million.

Recent amendments to the HGB area SIP to reduce highly reactive VOCs from chemical and petroleum industry plants seek to reduce fugitive VOC emissions. The proposed leak detection and repair requirements will add quarterly monitoring for a variety of components that have been found to leak, yet in most cases are not currently required to be monitored. This rule would eliminate the leak skip option for valves, and would require an additional round of monitoring during the third quarter (July-September) of each year. The annual costs for this requirement were estimated using estimates made by the TCEQ which include the annual costs of increased monitoring frequency, adding new monitoring, repair costs and equipment upgrades. This estimated annual compliance cost for the HGB area is estimated to be $133.5 million.

For cooling tower controls, the HGB SIP measure establishes a one part per million by weight VOC concentration rise as a leak definition for cooling tower systems. The measure further requires monthly inspection of the cooling water to detect VOC leaks and allows a maximum of 45 days for any leak to be repaired after it is detected. Based on cost estimates from various vendors and TCEQ staff regarding purchase and installation of continuous flow monitors and sampling expenses, the initial capital cost and any associated first year operating expenses are estimated to be $70,000 for each cooling tower and heat exchange system in the HGB area. Annual operating and maintenance costs are estimated to be $52,000 for each cooling tower heat exchange system. For the estimated 115 affected units in the HGB area, regional compliance costs are estimated to be $2.1 million in capital and $6 million in annual operating and maintenance cost. The resulting annualized cost estimate for this measure in the HGB area is $6.2 million.

The total annualized cost of these HRVOC emission reduction measures is $146 million.

PM-10 SIP Measures

In this section we describe the estimates of costs that have been incurred to meet the PM-10 ambient air quality standards since 1990. These estimates were developed by reviewing PM-10 SIPs and associated control cost estimates for selected serious PM-10 nonattainment areas. The serious PM-10 nonattainment area SIPs that were reviewed included those for Coachella Valley, CA, South Coast, CA, Clark County, NV, and Maricopa County, AZ. The estimated compliance cost for these four PM-10 nonattainment areas was $24 to $29 million. In these areas, most of the compliance cost was in controlling fugitive dust emissions from paved and unpaved roads and construction activities. More information about this serious PM-10 nonattainment area analysis is provided in Appendix C.

To estimate the compliance costs for the remaining serious PM-10 nonattainment areas and the moderate PM-10 nonattainment areas, a model PM-10 SIP was developed that applied control measures in AirControlNET to the three major fugitive dust source categories listed above to estimate control costs. Controls on each of these source categories are judged to be representative of the control measures applied in PM-10 nonattainment areas in the western United States, where most of the PM-10 nonattainment areas were found. The total estimated cost to attain the PM-10 NAAQS is estimated to be $125 to $130 million per year. Exhibit 5-11 summarizes the estimated costs of attaining the PM-10 NAAQS at the state-level. This table includes the costs for serious and moderate PM-10 nonattainment areas. A list of all non-attainment areas addressed in our PM-10 analysis is included in Table C-8 in Appendix C

Exhibit 5-11. Cost Summaries by State for PM-10 NAAQS

State	Annual Cost (million 1999$)
Arizona	18.1
California	24.5
Colorado	9.0
Connecticut	0.4
Idaho	11.1
Illinois	4.0
Indiana	2.1
Minnesota	0.2
Montana	7.6
Nevada	17.3
New Mexico	11.8
New York	0.1
Ohio	1.0
Oregon	6.9
Pennsylvania	0.8
Texas	1.5
Utah	2.3
Washington	7.7
West Virginia	0.4
Wyoming	2.7
TOTAL	**129.6**

Summary of Results for this Sector

Exhibit 5-12 summarizes the non-EGU point source costs for the major cost elements discussed in the proceeding sections. This table shows that the annual costs expected to be incurred by this sector range from $2.3 billion in 2000 to $4.25 billion in 2020.

Exhibit 5-12. Non-EGU Point Source Cost Summary

	Annual Cost (million$)		
	2000	2010	2020
NO_x SIP Call	6	116	118
MACT	1,152	2,547	2,547
National VOC Rules	250	291	353
RACT and New CTGs	350	398	477
Refinery Settlements	0	255	289
1-Hour Ozone SIP Measures			
AirControlNET-Based Analyses	317	317	317
CA Area SIP Costs	505	505	505
H-G HRVOC Measures	0	146	146
PM-10 SIP Measures	130	130	130
TOTAL	**2,460**	**4,414**	**4,529**

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CHAPTER 6 - NONPOINT SOURCE ANALYSIS

Many of the Title I requirements of the CAAA of 1990 provisions affect VOC emissions from nonpoint sources. These requirements include Title I RACT, new control technique guidelines (CTGs), and national rules. Title I RACT controls were applied in moderate and above 1-hour ozone nonattainment areas and throughout the Ozone Transport Region. Title I national rules included those that reduce VOC emissions from consumer products, architectural and industrial maintenance (AIM) coatings, autobody refinishing, hazardous waste transportation, storage, and disposal facilities (TSDFs), municipal landfills, and marine vessel loading. Cost per ton estimates were available for each of the national rules and these values were applied in this analysis to estimate compliance costs.

Title I RACT requirements were identified in the First Prospective analysis - rather than duplicate effort for this historical program, we rely on the incremental emissions estimates from that analysis here, but update the cost estimates to reflect cost estimates in the current version of AirControlNET. Pages 33-42 of the First Prospective emissions report (Pechan 1998) identifies the source categories, control levels and cost per ton values that were used to estimate Title I RACT costs for the First Prospective. Table VII-13 in the First Prospective emissions report summarizes the Title I RACT area source unit costs that were applied in this analysis. The information from Table VII-13 was used to identify the control technique in AirControlNET that could achieve the expected emission reduction. These RACT-level control techniques were then applied to the 1990 NEI projected to 2000, 2010 and 2020 (the without CAAA scenario) to estimate the tonnage reductions achieved by each RACT requirement for each source category. Exhibit 6-1 summarizes the estimated emission reductions (control efficiencies), rule effectiveness values, and average cost per ton applied in this analysis to estimate the area (nonpoint) source costs of national, regional and local regulations to reduce VOC emissions from this sector post-1990.

Exhibit 6-2 shows the estimated cost for the 1-hour ozone NAAQS compliance measures applied to area (nonpoint) source for the ozone nonattainment areas in California. The columns labeled emission reduction target provide the estimated emission reductions via regulation (in total) in the air districts in California. The column labeled “Available Reductions in AirControlNET” indicates measures identified in AirControlNET applied to achieve the needed reductions. The selected measures are those that are used to estimate the annual cost in the right-most columns. Note that there is one area (Monterey Bay) where there were no measures available to meet the 491 ton VOC emission reduction target - costs to adopt those unidentified measures are not reflected in this report draft.

Exhibit 6-1. Area Source VOC Cost Inputs by Source Category

Source Category	VOC Control-Effectiveness (%)	VOC Rule-Effectiveness (%)	Cost Per Ton (1999$)
Architectural & industrial maintenance coating	20	100	223
Automobile refinishing	37	100	148
Bulk Terminals	78	100	243
Consumer solvents	20	48.6	306
Dry cleaning – petroleum	44	100	590
Municipal solid waste landfills	82	100	1,317
Oil and natural gas production fields	95	80	419
Paper surface coating	37	80	419
Pharmaceutical manufacture	37	80	3,424
SOCMI batch reactor processes	78	80	4,283
Service stations - stage I-truck unloading	95	80	984
Treatment, storage and disposal facilities	94	100	186
Web Offset Lithography	80	80	-132
OTC AIM Coating Rule	44.8	100	6,628
OTC Solvent Cleaning Rule	66	100	1,400
OTC Consumer Products Rule	34.2	48.6	1,032
OTC Mobile MER Rule	61	100	2,534
OTC Portable Gas Container Rule	33	100	581

Note: VOC control- and rule-effectiveness are derived from EPA guidance to states on the extent to which these measures may be credited toward forecast emissions reductions in state implementation plans.

Exhibit 6-2. 1-Hour Ozone NAAQS Area Source Control Cost Estimates

Nonattainment Area	Emission Reduction Target (tons)		Available Reductions in AirControlNET (tons)		Annual Cost (million 1999$)	
	NO_x	VOC	NO_x	VOC	NO_x	VOC
Baton Rouge	-	-	-	-	-	-
Beaumont-Port Arthur	-	-	-	-	-	-
Dallas-Fort Worth	-	-	-	-	-	-
Houston Galveston Area	-	-	-	-	-	-
Los Angeles-South Coast	15	18,458	39	19,103	-	52
Monterey Bay	-	491	-		-	(0)
Sacramento Metro	-	200	-	250	-	0
San Diego	-	-	-	-	-	-
San Francisco-Bay Area	241	3,992	313	4,087	0	5
San Joaquin Valley	1,227	5,865	2,109	6,287	0	4
San Joaquin Valley-Merced		294	-	321	-	1
Santa Barbara-Santa Maria-Lomp	-	-	-	-	-	-
Southeast Desert Modified	-	-	-	-	-	-
Ventura Co CA	-	-	-	-	-	-
TOTALS					$0	$62

Note: Costs for Monterey Bay NAA are slightly negative because the VOC measures employed are net cost saving.

Exhibit 6-3 summarizes the nonpoint source cost analysis for the major components. The cost estimated for the first two elements in the table (CTGs plus RACT and OTC Model Rules) are summarized from the values listed as area source measures in Exhibits 5-8 through 5-10 in Chapter 2.

Exhibit 6-3. Nonpoint Source Cost Analysis Summary

	Annual Costs (million $)		
	2000	**2010**	**2020**
CTGs Plus RACT	$339	$389	$473
OTC Model Rules	102	159	204
1-Hour Ozone NAAQS	62	62	62
TOTALS	$503	$610	$739

References

Pechan, 1998: *Emissions Projections for the Clean Air Act Section 812 Prospective Analysis*, prepared for Industrial Economics, Incorporated, June 1998.

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CHAPTER 7 - LOCAL CONTROL MEASURES ANALYSIS

The cost analysis 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 $PM_{2.5}$ NAAQS attainment. This chapter describes the analysis that was performed to estimate the control cost 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 are all proposed or final rules that have been issued recently by EPA. The baseline for performing this local control measures evaluation is the core scenario from the *with-CAAA* 2010 and 2020 cases.

The local control measure analysis was performed in three sequential 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.

8-Hour Ozone Analysis

This analysis focused on the implementation costs in nonattainment areas in the United States. 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 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 economic analysis.

The second group consists of 8-hour ozone nonattainment areas for which certain mandatory 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 reasonably 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. This decision was motivated primarily by poor model performance at the time simulations were conducted by EPA for ozone concentrations in various ozone nonattainment areas within California. As a result, Pechan developed alternative methods to estimate VOC and NO_x emission reductions targets to meet the 8-hour ozone NAAQS for California nonattainment areas. These methods are described in more detail in Appendix E of this document.

For California the 8-hour ozone NAAQS attainment costs were estimated for serious and above nonattainment areas. 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).

For each area, publicly available 8-hour ozone modeling results and/or draft 8-hour ozone SIPs were consulted and inquiries were made to State employee contacts when emissions reduction target information was not available. Since these nonattainment areas are classified as serious or above, we assumed that RACT requirements had previously been met and no further RACT control measures were needed to satisfy the RACT requirement. Similarly since the VOC reasonable further progress (RFP) requirements for these nonattainment areas were included in the 2010 VOC emission reduction targets (see Appendix E) no additional control measures were needed. One consequence of this approach is that the 2010 costs for California presented here include the cost of satisfying RFP requirements in addition to reductions needed to meet 8-hour ozone NAAQS in 2010 even though the attainment date in two areas is not until 2013.

RACT and I/M

RACT controls on EGU and non-EGU point sources were applied in the areas where RACT requirements had not yet been met. 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 using the following 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
- If multiple controls meeting the above criteria are available, then the control measure with the lowest NO_x control efficiency from all that are available for that source is applied (i.e., RACT represents the minimum available control that nonetheless meets the above criteria).

I/M controls are then applied to counties where required. Once I/M and RACT controls were applied, the costs 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.

Reasonable Further Progress (RFP) Requirements

The reasonable further progress requirement (RFP) is an attainment program element requiring incremental reductions in the emissions of the applicable air pollutant pursuant to Part D of the CAA and its Amendments. The RFP requirements 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 7-1 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 OTC model rules to reduce VOC solvent emissions. The 2008 emissions were estimated by interpolating 2002 and 2010 emission estimates.

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 of the nonattainment area boundary for VOC reductions and within 200 km radius of the nonattainment area boundary 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.

Exhibit 7-1. 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%
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%
San Diego, CA	73,409	9,265	12.6%
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%

Note: Estimates for most California 8-hour ozone NAAs were developed separately - see text and Appendix E for details.

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 and 2010 yields 2008 emissions = 95,267 tons

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

Additional VOC tons required = (2008 Emissions) - (85 percent of discounted 2002 Emissions)
= (95,267) - (0.85 x 96,484)
= 13,256 tons

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 of the nonattainment area boundary for VOC reductions and within 200 km radius of the nonattainment area boundary for NO_x reductions are selected on a least cost basis, as described above for RFP.

Marginal Cost Analysis

Exhibit 7-2 presents the marginal and average cost per ton, by metropolitan area, of the NO_x and VOC emissions reductions associated with the RACT, I/M, and RFP measures described above.[99] As the table indicates, marginal and average costs per ton of NO_x and VOC abated vary significantly by area. These differences largely reflect the distribution of NO_x and VOC reductions across different source categories and the stringency of the Federal, state, and local programs that were on the books in each area as of September 2005 (the RACT, I/M, RFP, and additional measures reflected in Exhibit 7-2 are incremental to programs in place in September 2005). For example, the average costs per ton of NO_x reduced are highest in Allegan County, Michigan and the Detroit-Ann Arbor area, both of which we expect to rely exclusively on reductions from onroad sources, which tend to be more expensive to control on a per ton basis than large industrial and utility point sources. Similarly, the average and marginal cost per ton of NO_x abated is lowest in the Atlanta area. This reflects the area's ability to achieve most its NO_x reductions through additional controls at electric utilities. Based on the local controls analysis presented in the Second Prospective emissions report, we estimate that Atlanta will need to reduce NO_x emissions by an additional 7,223 tons in 2010 to demonstrate further progress toward compliance with the 8-hour ozone NAAQS and that 98 percent of this reduction can be achieved through additional controls at electric utilities. Although we expect other areas to also rely heavily on reductions at utilities, the cost of reducing EGU NO_x emissions in the Atlanta area is lower than in other areas because utilities are not regulated as stringently in Georgia as in other regions. For example, although we expect the Raleigh area to achieve most of its NO_x reductions through electric utility controls, the marginal and average cost per ton of NO_x abated is high in Raleigh relative to Atlanta because North Carolina emissions requirements for electric utilities are more stringent than Georgia's requirements. In other words, utilities in North Carolina have already implemented the controls at the lower end of their marginal cost function.

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[99] As indicated above, our analysis of RACT, I/M, and RFP reflects only identified measures included in version 4.1 of AirControlNet.

Exhibit 7-2. Marginal Cost Per Ton for Identified Local Controls to Meet the 8-Hour Ozone NAAQS

Nonattainment Area	Marginal Cost per ton		Average Cost per ton	
	NOx	VOC	NOx	VOC
Allegan Co, MI	$ 26,145	$ 9,509	$ 20,860	$ 4,404
Atlanta, GA	$ 50	$ 1,032	$ 10	$ 788
Baltimore, MD	$ 8,608	$ 9,508	$ 2,437	$ 2,839
Beaumont-Port Arthur, TX	$ 27,588	$ 24,990	$ 3,389	$ 4,412
Buffalo-Niagara Falls, NY	$ 2,087	$ 1,433	$ 1,198	$ 1,253
Chicago-Gary-Lake County, IL-IN	$ 3,381	$ 9,509	$ 1,629	$ 4,096
Chicago-Gary-Lake County, IL-IN (Cook, IL & Lake, IN)	$ 5,659	$ 9,508	$ 2,470	$ 3,925
Cleveland-Akron-Lorain, OH	$ 26,091	$ 1,433	$ 770	$ 1,179
Columbus, OH	$ 27,045	$ 1,433	$ 7,425	$ 1,177
Dallas-Fort Worth, TX	$ 27,453	$ 18,511	$ 3,976	$ 3,591
Detroit-Ann Arbor, MI	$ 26,444	$ 2,908	$ 20,556	$ 1,962
Door Co, WI	$ 26,423	$ 2,677	$ 2,842	$ 1,411
Houston-Galveston-Brazoria, TX	$ 27,495	$ 17,941	$ 3,676	$ 3,491
Indianapolis, IN	$ 2,710	$ -	$ 1,418	$ -
Kent and Queen Anne's Cos, MD	$ 28,564	$ 9,509	$ 12,638	$ 3,384
Knoxville, TN	$ 28,118	$ 17,967	$ 16,931	$ 1,689
Los Angeles South Coast Air Basin, CA	$ -	$ 1,433	$ -	$ 1,038
Milwaukee-Racine, WI	$ 8,608	$ 2,908	$ 2,567	$ 1,882
Nevada Co. (Western Part), CA	$ -	$ -	$ -	$ -
New York-N. New Jersey-Long Island,NY-NJ	$ 9,635	$ 9,509	$ 2,582	$ 3,638
Philadelphia-Wilmin-Atlantic Ci,PA-NJ-MD	$ 8,608	$ 9,511	$ 2,738	$ 3,496
Providence (All RI), RI	$ 8,608	$ -	$ 2,895	$ -
Raleigh-Durham-Chapel Hill, NC	$ 27,687	$ 18,465	$ 9,760	$ 2,548
Sacramento Metro, CA	$ -	$ 9,508	$ -	$ 3,591
San Diego, CA	$ -	$ 9,508	$ -	$ 3,862
San Joaquin Valley, CA	$ -	$ 9,509	$ -	$ 3,837
Sheboygan, WI	$ 8,608	$ 2,908	$ 2,606	$ 1,834
South Bend-Elkhart, IN	$ 2,174	$ 9,508	$ 1,603	$ 3,491
Ventura Co, CA	$ -	$ 9,508	$ -	$ 3,640
Washington DC	$ 8,608	$ 9,509	$ 1,258	$ 1,843
Youngstown-Warren-Sharon, PA-OH	$ 26,899	$ 17,099	$ 5,204	$ 2,036

Note also that the targets for 8-hour ozone compliance were determined by air quality modeling and do not necessarily present the optimal, least cost solution to ozone compliance. In other words, the targets represent a feasible emissions reduction path to 8-hour ozone compliance, but other, less costly paths may exist that involve a different mix of NO_x and VOC reductions.

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 costs 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 version 4.1 and a list of potentially affected non-EGU BART-eligible sources previously developed by EPA. The control measure database contains a listing of control strategies and the resulting emission reductions, control costs, and annualized capital and 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.

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.

$PM_{2.5}$ 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 are 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 costs of controlling 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.[100] As a practical matter, a $10,000 per ton upper limit is applied in this analysis. This approach is consistent with prior analyses, including the first 812 Prospective Study. The approach rests on the assumption that requirements where per ton costs exceed $10,000 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. (This analysis includes as many RACM measures as matched with measures in AirControlNET. These assignments were made based on the judgment of the Project Team.)

EPA and States are currently working to develop a list of likely control measures anticipated for inclusion in $PM_{2.5}$ SIPs. While area-specific SIP control measures are not available for this analysis, 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. 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 $10,000 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.

Results

This section includes summaries of the cost estimates of applying control measures to meet the 8-hour ozone NAAQS, the $PM_{2.5}$ NAAQS, and the CAVR requirements.

Exhibit 7-3 summarizes estimated state-level and national 8-hour ozone NAAQS and $PM_{2.5}$ NAAQS attainment costs for 2010. CAVR costs are not shown in this table because they are not expected to be incurred in 2010. The estimated national cost of 8-hour ozone and $PM_{2.5}$ NAAQS compliance in 2010 are $2.7 billion and $0.7 billion, respectively - with a total annual cost of $3.4 billion. The expected costs of 8-hour NAAQS compliance are dominated by the costs from a relatively small

[100] Note that the rule has since been finalized, in two Phases, with Phase 2 completed in November 2005.

number of 8-hour ozone nonattainment areas. About 76 percent of the non-California estimated compliance cost is expected to be incurred in seven nonattainment areas:

1. Chicago- Gary-Lake County, IL
2. Dallas- Ft. Worth, TX
3. Detroit-Ann Arbor, MI
4. Houston-Galveston-Brazoria, TX
5. New York- North New Jersey- Long Island, NY
6. Philadelphia- Wilmington- Atlantic City, DE-NJ-PA
7. San Joaquin Valley

Note that the cost of reducing any residual ozone nonattainment tons is not included in the cost estimates presented here. Costs of controlling these remaining tons are estimated in Appendix E and summarized in the Key Uncertainties section of this chapter.

$PM_{2.5}$ NAAQS cost estimates largely reflect the cost of applying RACT and RACM in the nonattainment areas, so these 2010 costs are more evenly distributed across the nonattainment areas than for ozone. At the state level, the highest 2010 $PM_{2.5}$ nonattainment costs are predicted for California, and the mid-east region that includes Ohio, Pennsylvania, and West Virginia.

Exhibits 7-4 and 7-5 show the breakdown of 8-hour ozone NAAQS and $PM_{2.5}$ NAAQS costs by sector. Exhibit 7-4 shows that 53 percent of the 8-hour ozone NAAQS compliance cost is expected to be borne by the area source or nonpoint source sector. Key affected area source categories include consumer solvents, architectural and commercial coatings, automobile refinishing, and other miscellaneous coatings. Further on-road motor vehicles emission control costs are estimated to be $491 million in 2010, or 19 percent of the 8-hour ozone control national total. Non-EGU point sources and EGUs are estimated to be 20 percent and 8 percent of the national 2010 control cost, respectively, for 8-hour ozone NAAQS compliance.

Exhibit 7-5 shows the by sector breakdown for $PM_{2.5}$ NAAQS costs in 2010. These costs are dominated by control costs estimated to be incurred by the non-EGU point source sector (about 43 percent) and on-road mobile source sector (about 38 percent). The remaining 19 percent of the 2010 $PM_{2.5}$ NAAQS costs are somewhat evenly split among area, nonroad, and EGU point sources.

Exhibit 7-6 provides the local control measure cost summary for the 2020 projection year. This table summarizes state-level and national costs for the 8-hour ozone NAAQS, the $PM_{2.5}$ NAAQS, and the CAVR. Total national local control measure costs in 2020 are estimated to be $4.4 billion in 2020, up from $3.4 billion in 2010. Most of this increase is explained by the incidence of CAVR costs in the period between 2010 and 2020 that are not expected to be incurred in 2010. The 8-hour ozone NAAQS compliance costs increase slightly between 2010 and 2020 as areas control the emissions tons that would be higher in 2020 than in 2010 with source sector growth. CAVR costs are more evenly distributed across the states than NAAQS compliance costs, as NAAQS compliance costs are focused in and surrounding the nonattainment areas. CAVR costs are related to the presence or absence of the industries (source categories) that are BART-eligible.

$PM_{2.5}$ NAAQS cost estimates are lower in 2020 than in 2010 because some source categories like on-road vehicles have much lower direct $PM_{2.5}$ (and other PM precursor emissions) in 2020 because of cleaner fuels and/or more stringent emission standards. Hence, there is less opportunity for cost effective emission reductions from some source sectors in 2020 than in 2010.

Exhibit 7-7 summarizes expected 8-hour ozone NAAQS compliance costs in 2020 by sector. The distribution of costs by sector changes somewhat in 2020 (from 2010). On-road vehicle emission control costs (from local measures) are 19 percent lower in 2020 than in 2010 as Tier 2 and HDDV emission standards penetrate the fleet (making further on-road vehicle emission controls less necessary or cost effective). Costs for all other sectors are slightly higher in 2020 compared with 2010.

Exhibit 7-8 displays the 2020 estimated cost for meeting CAVR requirements by industry (i.e., SIC code). This table shows that 87 percent of the CAVR costs for non-EGUs are expected to be borne by four industries: paper and allied products; chemicals; petroleum; and stone, clay and glass. All other industries are expected to incur costs around 13 percent of the $1 billion total for CAVR.

Exhibit 7-9 presents 2020 estimated $PM_{2.5}$ NAAQS compliance costs. This $542 million total is 28 percent below the 2010 estimate. The lower 2020 value is attributable to reduced on-road mobile source costs, as federal programs implemented during the 2000 to 2010 period achieve high fleet penetration rates, obviating the need for retrofits.

Exhibit 7-3. 2010 Local Control Cost Summary

	Annual Cost (million 1999$)		
State	**Ozone NAAQS**	**PM NAAQS**	**Total**
Alabama	N/A	50.3	50.3
California	378.4	117.3	495.6
Connecticut	104.9	4.3	109.2
Delaware	20.6	5.8	26.4
DC	0.3	0.3	0.6
Georgia	3.7	27.3	30.9
Illinois	244.9	8.3	253.2
Indiana	96.7	50.5	147.3
Kentucky	N/A	14.2	14.2
Maryland	140.2	8.4	148.6
Michigan	139.6	48.9	188.6
Missouri	N/A	30.0	30.0
Montana	N/A	0.2	0.2
New Jersey	203.3	16.7	219.9
New York	334.6	21.0	355.6
North Carolina	28.4	7.6	36.0
Ohio	82.9	120.4	203.3
Pennsylvania	288.9	92.0	380.9
Rhode Island	3.8	N/A	3.8
Tennessee	24.1	30.3	54.4
Texas	437.7	N/A	437.7
Virginia	11.8	6.3	18.1
West Virginia	N/A	90.7	90.7
Wisconsin	84.5	N/A	84.5
TOTAL	**2,629.4**	**750.6**	**3,380.0**

Note: Entries of N/A above mean that there available forecasts indicate there will be no non-attainment areas for that NAAQS requirement in the indicated state in 2010.

Exhibit 7-4. 2010 8-Hour Ozone NAAQS Implementation Cost by Sector

Sector	Annual Cost (million 1999$)
Area	1,404.3
Mobile	491.6
Non-EGU	534.4
EGU	199.1
TOTAL	**2,629.4**

Exhibit 7-4. 2010 $PM_{2.5}$ NAAQS Implementation Cost by Sector

Sector	Annual Cost (million 1999$)
Area	31.2
Mobile	288.6
Nonroad	41.4
Non-EGU	323.2
EGU	66.2
TOTAL	**750.6**

Exhibit 7-6. 2020 Local Control Cost Summary

	Annual Cost (million 1999$)			
State	**Ozone NAAQS**	**PM NAAQS**	**CAVR**	**Total**
Alabama	N/A	59.5	55.9	115.4
Arizona	N/A	N/A	2.5	2.5
Arkansas	N/A	N/A	1.5	1.5
California	418.8	58.8	29.8	507.4
Colorado	N/A	N/A	21.2	21.2
Connecticut	104.9	2.8	0.5	108.2
Delaware	21.9	7.1	0.3	29.3
DC	0.4	N/A	N/A	0.4
Florida	N/A	N/A	51.0	51.0
Georgia	4.8	22.0	42.7	69.5
Idaho	N/A	N/A	9.2	9.2
Illinois	298.7	9.5	19.7	327.9
Indiana	115.8	27.2	32.8	175.8
Iowa	N/A	N/A	31.2	31.2
Kansas	N/A	N/A	11.1	11.1
Kentucky	N/A	8.3	22.6	31.0
Louisiana	N/A	N/A	164.4	164.4
Maine	N/A	N/A	31.2	31.2
Maryland	123.2	3.8	1.7	128.7
Massachusetts	N/A	N/A	3.4	3.4
Michigan	163.8	28.6	67.9	260.3
Minnesota	N/A	N/A	20.8	20.8
Mississippi	N/A	N/A	33.1	33.1
Missouri	N/A	20.4	4.6	25.0
Montana	N/A	N/A	1.1	1.1
Nebraska	N/A	N/A	4.7	4.7
Nevada	N/A	N/A	0.3	0.3
New Hampshire	N/A	N/A	2.7	2.7
New Jersey	198.8	11.5	0.8	211.1
New Mexico	N/A	N/A	11.4	11.4
New York	389.8	16.4	9.8	416.0
North Carolina	28.7	2.4	22.1	53.2
Ohio	94.7	81.9	46.3	222.9
Oklahoma	N/A	N/A	17.5	17.5
Oregon	N/A	N/A	6.6	6.6
Pennsylvania	283.7	70.6	9.1	363.4
Rhode Island	0.8	N/A	N/A	0.8
South Carolina	N/A	N/A	51.1	51.1
Tennessee	30.8	24.2	48.7	103.7
Texas	488.2	N/A	4.1	492.3
Virginia	11.6	1.3	N/A	12.8
Washington	N/A	N/A	28.0	28.0
West Virginia	N/A	85.5	14.4	99.9
Wisconsin	69.8	N/A	43.1	112.9
Wyoming	N/A	N/A	15.3	15.3
TOTAL	**2,849.2**	**541.6**	**996.4**	**4,387.2**

Note: Entries of N/A above mean that available forecasts indicate there will be no non-attainment areas for that NAAQS requirement, or that no BART-eligible sources exist, in the indicated state in 2020.

Exhibit 7-7. 2020 8-Hour Ozone NAAQS Implementation Cost by Sector

Sector	Annual Cost (million 1999$)
Area	1,682.0
Mobile	399.3
Non-EGU	568.8
EGU	199.1
TOTAL	**2,849.2**

Exhibit 7-8. 2020 CAVR Implementation Cost by 2 digit SIC for Non-EGU Point Sources

SIC (2-digit)	SIC Name	Annual Cost (million 1999$)
12	Coal Mining	0.6
13	Oil and Gas Extraction	18.5
14	Nonmetallic Minerals, Except Fuels	5.1
20	Food and Kindred Products	38.8
22	Textile Mill Products	1.4
24	Lumber and Wood Products	1.1
26	Paper and Allied Products	274.4
28	Chemicals and Allied Products	227.9
29	Petroleum and Coal Products	200.0
30	Rubber and Misc. Plastics Products	0.5
32	Stone, Clay, and Glass Products	158.0
33	Primary Metal Industries	48.9
35	Industrial Machinery and Equipment	0.1
37	Transportation Equipment	1.3
49	Electric, Gas, and Sanitary Services	6.8
65	Real Estate	N/A
82	Educational Services	8.2
91	Executive, Legislative, and General	N/A
97	National Security and Intl. Affairs	N/A
	TOTAL	**991.6**

Exhibit 7-9. 2020 $PM_{2.5}$ NAAQS Implementation Cost by Sector

Sector	Annual Cost (million 1999$)
Area	37.3
Mobile	128.8
Nonroad	13.3
Non-EGU	309.1
EGU	53.1
TOTAL	**541.6**

Evaluation of Unidentified Measures

The modeled VOC and NO_x emission reductions for some 8-hour ozone nonattainment areas in the local control measures analysis are not sufficient to bring them into attainment of the 8-hour standard (based on the emission reduction targets that were used). Identifiable control measures are insufficient to achieve the needed VOC emission reductions in four nonattainment areas outside of California: Chicago, Houston-Galveston, New York, and Philadelphia. In total, the VOC emissions shortfall in these four 8-hour ozone nonattainment areas is about 352,000 tons per year in 2010. At a cost of $10,000 per ton, it would cost about $3.5 billion to reduce these residual tons to the level needed to reach full attainment of the 8-hour ozone NAAQS. Within the State of California, the identifiable control measures are unable to achieve the needed 2010 emission reductions in the San Joaquin Valley—where there is an expected 12,916 ton per year VOC shortfall. At $10,000 the additional cost of unidentified VOC measures in 2010 in California would be $129 million.

There are also expected NO_x emission reduction shortfalls in eight 8-hour ozone nonattainment areas in 2010, with these shortfalls ranging from as little as 1,341 tons (in Cleveland) to 150,000 tons (in the New York City nonattainment area). In total, these non-California area NO_x emission reduction shortfalls total 324,940 tons per year in 2010. At a cost of $10,000 per ton, it would cost about $3.25 billion to reduce these residual tons to the level to reach full attainment of the 8-hour ozone NAAQS. Within California, the remaining NO_x tons in 2010 are estimated to be 7,883 tons per year, which adds another $79 million to the estimated NAAQS compliance cost.

While a marginal cost of $10,000 per ton to reduce these remaining VOC and NO_x tons seems to be a reasonable value to use given the costs being incurred via strategies to achieve emission reductions via identified measures, this marginal cost is likely to vary according to the area involved. Variables that affect the amounts spent on air pollution control include the source mix in each area, the quantity of emission reduction needed relative to uncontrolled emission rates, and the willingness of the decision-makers in an area to impose control costs on the sources in their area.

Various assumptions have been made about the cost of controlling these residual tons under the CAAA of 1990 dating back to 1988 when analyses were being performed of the Congressional bill alternatives that ultimately produced the 1990 Amendments. A 1988 EPA-sponsored study found that "one of the important findings of this study (and other similar studies) was that there are not enough identifiable control measures to calculate how much it might cost for all metropolitan areas to attain the ozone NAAQS. Therefore, the cost of controlling residual tons after all identifiable controls are applied was estimated using a range of $2,000 to $10,000 per ton" (Pechan, 1988)

California's requirement for sources to report the costs of emission offsets provides some evidence about the potential costs to control residual ozone nonattainment VOC and NO_x tons (ARB, 2006). Since 1993, California has required local air quality management districts to collect information about the cost of offset transactions from stationary source owners who purchase offsets as required by district New Source Review (NSR) programs. State law also requires districts to adopt emission reduction credit banking programs. Districts are required to collect specific information about offset transactions, including the price paid in dollars per ton, the pollutant traded, the amount traded and the year of the transaction. Districts that are not required to submit a plan for attainment of state ambient air quality standards and that also meet federal air quality standards are exempt from these requirements.

A total of 340 transactions occurred during 2005 in California. Excluding 70 subsidiary transactions, where there were no associated costs, leaves 270 transactions. Of these, 46 were for NO_x and 163 were for hydrocarbons. These transactions generally represent trades of offsets that are valid for the lifetime of the permitted source using the offsets. This is in contrast to other types of credits that are valid for much shorter time periods (like one year). During 2005, the median price per ton for NO_x

offsets was \$25,000. The NO_x average was \$43,982 per ton. (California's NO_x offset costs would be expected to be higher than in most other areas of the country because of the need for high levels of emission reductions and because the fuel mix is dominated by natural gas, whose NO_x emissions are more costly to control than those in areas where coal dominates.) Reviewing the average NO_x offset cost in California dating back to 1993 shows that the cost stayed below \$20,000 per ton until the year 2000, and has increased significantly since then, with the average for the 2003-2005 period being \$40,000 per ton or more throughout this period.

For VOC, the median offset price was \$6,849 during 2005 in California, with an average of \$6,328 per ton. The highest VOC price per ton was \$26,950 and the lowest was \$200. The 12-year trend in the average cost of VOC offsets has shown that this average stays between \$6,000 and \$12,000 per ton in most years with no perceptible upward or downward long-term trend.

Other evidence that can be used to estimate the marginal cost of reducing NO_x tons is provided by the NO_x Budget Trading Program in the eastern United States (EPA, 2006). The 2005 program compliance report by EPA shows that the NO_x allowance price is within the range of \$2,000 to \$4,000 per ton. Results also show that most of the add-on controls being applied to sources in the control region are being installed at large coal-fired EGUs, which are the most cost effective to control. Only about 3 percent of the industrial coal-fired units use add-on NO_x controls. This suggests that in areas that will require add-on NO_x controls to meet emission reduction targets, the cost to reduce industrial source NO_x tons will be higher than the allowance prices observed so far in the NO_x Budget Trading Program market.

References

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EPA 2006: "NO_x Budget Trading Program: 2005 Program Compliance and Environmental Results," U.S. Environmental Protection Agency, Office of Air and Radiation, EPA-430-R-06-013, September 2006.

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