Control Measure Evaluations: The Control Measure Data Base for the National Emissions Trends Inventory (ControlNET)

Draft Report

CONTROL MEASURE EVALUATIONS:
THE CONTROL MEASURE
DATA BASE FOR THE NATIONAL
EMISSION TRENDS INVENTORY
(ControlNET)

DRAFT REPORT

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TABLES

ACRONYMS AND ABBREVIATIONS

μm	micrometers
acfm	actual cubic feet per minute
ACT	Alternative Control Techniques
AIM	Architectural and Industrial Maintenance
BAAQMD	Bay Area Air Quality Management District
BACM	Best Available Control Measures
BID	background information document
Btu/lb	British thermal units per pound
C&C	consumer and commercial
CAA	Clean Air Act
CARB	California Air Resources Board
CATC	Clean Air Technology Center
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
COA	Census of Agriculture
CTC	Control Technology Center
CTG	control technique guideline
DMA	dimethylaniline
DPR	Department of Pesticide Regulation
EPA	U.S. Environmental Protection Agency's (EPA's
ESP	electrostatic precipitator
FBC	fluidized bed combuster
FCCU	Fluid Catalytic Cracking Units
FGD	flue gas desulfurization
FIP	Federal Implementation Plan
ft/min	feet per minute
g/L	grams per liter
gr/100 scf	grains per 100 standard cubic feet
H_2S	hydrogen sulfide
HAP	hazardous air pollutant
HBr	hydrogen bromide
HDDVs	heavy-duty diesel vehicles
HDV	heavy-duty vehicle
HDVIP	Heavy-Duty Vehicle Inspection Program
HF	hydrogen fluoride
HMA	hot mix asphalt
HPWH	heat pump water heater
I/M	Inspection and Maintenance
IAPCS	Integrated Air Pollution Control System
ICI	industrial, commercial, and institutional
IPM	Integrated Pest Management
kg/head-yr	kilograms per head per year
kPa	kilopascals
LDGTs	light-duty gasoline trucks

LDGVs	light-duty gasoline vehicles
LDTs	light-duty trucks
LDVs	light-duty vehicles
LEVs	low-emission vehicles
LNG	liquified natural gas
LP	liquid propane
MACT	maximum achievable control technology
mg/nm^3	milligrams per normal cubic meters
MMBtu	million British thermal units
MW	megawatts
MWC	Municipal Waste Combustors
NAAQS	national ambient air quality standards
NESHAP	National Emission Standard for Hazardous Air Pollutants
NET	National Emission Trends
NGR	natural gas reburn
NH$_3$	ammonia
NO$_x$	oxides of nitrogen
NPI	National Particulates Inventory
NSPS	New Source Performance Standards
NSSC	neutral sulfite semichemical
O&M	operation and maintenance
OAQPS	Office of Air Quality Planning and Standards
OTC	Ozone Transport Commission
OTR	Ozone Transport Region
PSIP	Periodic Smoke Inspection Program
RACT	reasonably available control technology
RDF	refuse derived fuel
ROG	reactive organic gases
RWC	residential wood combustion
SCAQMD	South Coast Air Quality Management District
SCC	Source Classification Code
scfm	standard cubic feet per minute
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO$_2$	sulfur dioxide
SO$_3$	sulfur trioxide
SO$_x$	sulfur oxide
tpd	tons per day
tpy	tons per year
TSP	total suspended particulate
ULEV	ultra-low emission vehicle
UV/EB	ultraviolet and electronic beam
UV	ultraviolet
VMT	vehicle miles traveled
VOCs	volatile organic compounds

CHAPTER I
INTRODUCTION AND BACKGROUND

The U.S. Environmental Protection Agency's (EPA's) Office of Air Quality Planning and Standards (OAQPS) established national ambient air quality standards (NAAQS) for criteria pollutants under section 110 of the Clean Air Act (CAA). To support the development and implementation of the NAAQS and associated policies, EPA must develop and maintain data on emission sources and potential control measures. These databases assist EPA in analyzing the effects of different standards and/or control strategies. This report documents development of control measures for inclusion in a comprehensive control measure data base to support EPA analyses of policies and regulations. This data base is called ControlNET – the control measure data base for the National Emission Trends (NET) inventory.

ControlNET will cover all criteria pollutants: oxides of nitrogen (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), volatile organic compounds (VOCs), primary PM_{10}, primary $PM_{2.5}$, and ammonia (NH_3). The purpose of the ControlNET is to provide the data necessary for quick and comprehensive regulatory impact analyses. A memorandum documenting the ControlNET interface is provided separately. This report addresses the control measure research and evaluations conducted to provide the parameters necessary (control measure efficiency and cost) to model the impact of control measures using data from the NET inventory.

Table I-1 provides a complete listing of the control measures included in ControlNET as well as those which have been researched and evaluated for future inclusion (some experimental and future measures are documented in this report; however, modeling parameters could not be developed for inclusion in ControlNET). Those with an asterisk are documented within this report. For all other measures, refer to the Ozone/PM NAAQS report for documentation (*Additional Control Measure Evaluation for the Integrated Implementation of the Ozone and Particulate Matter National Ambient Air Quality Standards, and Regional Haze Program*, Pechan, July 17, 1997).

The remainder of this report is organized by sector and pollutant as follows:

VOC	Chapter II:	Stationary Source
NO_x	Chapter III:	Stationary Source
SO_2	Chapter IV:	Stationary Source
PM_{10} and $PM_{2.5}$	Chapter V:	Stationary Source
CO	Chapter VI:	Stationary Source
NH_3	Chapter VII:	Stationary Source
	Chapter VIII: Utility – All Pollutants	
	Chapter IX:	Highway Vehicles
Vehicles	Chapter X:	Nonroad Engines and

Table I-1
List of Control Measures

This Report	Measure ID	Source Category	Control Measure	Primary Pollutant
		Area Source Ammonia		
*	A00101	Cattle Feedlots	Chemical Additives	Ammonia
*	A00201	Poultry Operations	Chemical Additives	Ammonia
*	A00301	Hog Operations	Chemical Additives	Ammonia
		Point Source PM		
	PGELE	Grain Elevators	Oil Suppression	PM_{10}, $PM_{2.5}$
	PICIC	ICI Boilers - Coal	Fabric Filter	PM_{10}, $PM_{2.5}$
	PICIG	ICI Boilers - Gas	Fabric Filter	PM_{10}, $PM_{2.5}$
	PICIO	ICI Boilers - Oil	Fabric Filter	PM_{10}, $PM_{2.5}$
	PICIW	ICI Boilers - Wood	Electrostatic Precipitator	PM_{10}, $PM_{2.5}$
	P0101	Coke mfg - oven pushing	Partial shed to baghouse	PM_{10}, $PM_{2.5}$
	P0201	Coke sizing & screening - cold	Total enclosure to baghouse	PM_{10}, $PM_{2.5}$
	P0301	Iron & steel - casthouses	Total enclosure to baghouse	PM_{10}, $PM_{2.5}$
	P0402	Iron & steel - casthouses	Local hood venting to baghouse	PM_{10}, $PM_{2.5}$
	P0501	Iron&steel-hot metal transfer	Movable canopy to baghouse	PM_{10}, $PM_{2.5}$
	P0601	Mineral prod- dryers/furnaces	Venturi scrubber	PM_{10}, $PM_{2.5}$
	P0602	Mineral prod- dryers/furnaces	Fabric filter system	PM_{10}, $PM_{2.5}$
	P0701	Phosphate rock calcining	Venturi scrubber	PM_{10}, $PM_{2.5}$
	P0801	Prim. metals-material handling	Local hood/venturi scrubber	PM_{10}, $PM_{2.5}$
	P0802	Prim. metals-material handling	Local hood/fabric filter	PM_{10}, $PM_{2.5}$
	P0803	Prim. metals-material handling	Water suppression	PM_{10}, $PM_{2.5}$
	P0901	Min. prod. - material handling	Local hood/venturi scrubber	PM_{10}, $PM_{2.5}$
	P0902	Min. prod. - material handling	Local hood/fabric filter	PM_{10}, $PM_{2.5}$
	P0903	Min. prod. - material handling	Water suppression	PM_{10}, $PM_{2.5}$
	P1001	Coal clean.-material handling	Local hood/venturi scrubber	PM_{10}, $PM_{2.5}$
	P1002	Coal clean.-material handling	Local hood/fabric filter	PM_{10}, $PM_{2.5}$
	P1003	Coal clean.-material handling	Water suppression	PM_{10}, $PM_{2.5}$
	P1101	Surface mining-loading/storage	Water suppression	PM_{10}, $PM_{2.5}$
	P1201	Mineral prod- loading/storage	Water suppression	PM_{10}, $PM_{2.5}$
	P1301	Primary metals: vehicle travel	Chemical suppression	PM_{10}, $PM_{2.5}$
	P1401	Surface mining: vehicle travel	Chemical suppression	PM_{10}, $PM_{2.5}$
	P1501	Mineral prod. - vehicle travel	Chemical suppression	PM_{10}, $PM_{2.5}$
	P1601	Kraft process	ESP	PM_{10}, $PM_{2.5}$
	P1602	Kraft process	Scrubber	PM_{10}, $PM_{2.5}$
	P1603	Kraft process	Demister	PM_{10}, $PM_{2.5}$
	P1701	Coal cleaning - thermal dryers	Venturi scrubber	PM_{10}, $PM_{2.5}$

Table I-1 (continued)

This Report	Measure ID	Source Category	Control Measure	Primary Pollutant
	P1801	Ore crushing	Fabric filter	PM_{10}, $PM_{2.5}$
	P1901	Ore grinding	Fabric filter	PM_{10}, $PM_{2.5}$
	P2001	Ore crushing/grinding	Fabric filter	PM_{10}, $PM_{2.5}$
*	P10101	By-product Coke Manufacturing	Fabric Filter (Mech. Shaker)	PM_{10}, $PM_{2.5}$
*	P10102	By-product Coke Manufacturing	Venturi Scrubber	PM_{10}, $PM_{2.5}$
*	P10103	By-product Coke Manufacturing	Wet ESP - Wire Plate Type	PM_{10}, $PM_{2.5}$
*	P11101	Residual Oil (Industrial Boilers)	Venturi Scrubber	PM_{10}, $PM_{2.5}$
*	P12101	Fiberglass Manufacturing	Wet ESP - Wire Plate Type	PM_{10}, $PM_{2.5}$
*	P12201	Fiberglass Manufacturing	Dry ESP-Wire Plate Type	PM_{10}, $PM_{2.5}$
*	P13101	Feed and Grain Country Elevators	Fabric Filter (Mech. Shaker)	PM_{10}, $PM_{2.5}$
*	P14101	Grey Iron Foundries	Impingement-plate scrubber	PM_{10}, $PM_{2.5}$
*	P14102	Grey Iron Foundries	Dry ESP-Wire Plate Type	PM_{10}, $PM_{2.5}$
*	P14103	Grey Iron Foundries	Fabric Filter (Mech. Shaker)	PM_{10}, $PM_{2.5}$
*	P14104	Grey Iron Foundries	Venturi Scrubber	PM_{10}, $PM_{2.5}$
*	P15101	Catalytic Cracking Units	Dry ESP-Wire Plate Type	PM_{10}, $PM_{2.5}$
*	P16101	Feed and Grain Terminal Elevators	Fabric Filter (Mech. Shaker)	PM_{10}, $PM_{2.5}$
*	P17101	Glass Manufacture	Dry ESP-Wire Plate Type	PM_{10}, $PM_{2.5}$
*	P17201	Glass Manufacture	Fabric Filter (Pulse Jet Type)	PM_{10}, $PM_{2.5}$
*	P18101	Plywood/Particleboard Operations	Wet scrubber system	PM_{10}, $PM_{2.5}$
*	P18201	Plywood/Particleboard Operations	Wet ESP - Wire Plate Type	PM_{10}, $PM_{2.5}$
*	P19101	Asphalt Concrete	Fabric filter or venturi scrubber	PM_{10}, $PM_{2.5}$
	Area Source PM			
	PP110	Paved Road - Rural Interstate	Vacuum Sweeping	PM_{10}, $PM_{2.5}$
	PP130	Paved Road-Rural Oth Prin Art.	Vacuum Sweeping	PM_{10}, $PM_{2.5}$
	PP150	Paved Road-Rural Minor Art.	Vacuum Sweeping	PM_{10}, $PM_{2.5}$
	PP170	Paved Road-Rural Major Coll.	Vacuum Sweeping	PM_{10}, $PM_{2.5}$
	PP190	Paved Road-Rural Minor Coll.	Vacuum Sweeping	PM_{10}, $PM_{2.5}$
	PP210	Paved Road - Rural Local	Vacuum Sweeping	PM_{10}, $PM_{2.5}$
	PP230	Paved Road - Urban Interstate	Vacuum Sweeping	PM_{10}, $PM_{2.5}$
	PP250	Paved Road-Urban Oth Freeway	Vacuum Sweeping	PM_{10}, $PM_{2.5}$
	PP270	Paved Road-Urban Oth Prin Art.	Vacuum Sweeping	PM_{10}, $PM_{2.5}$
	PP290	Paved Road-Urban Minor Art.	Vacuum Sweeping	PM_{10}, $PM_{2.5}$
	PP310	Paved Road - Urban Collector	Vacuum Sweeping	PM_{10}, $PM_{2.5}$
	PP330	Paved Road - Urban Local	Vacuum Sweeping	PM_{10}, $PM_{2.5}$
	PU150	Unpaved Road-Rural Minor Art.	Chemical Stabilization	PM_{10}, $PM_{2.5}$

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Table I-1 (continued)

This Report	Measure ID	Source Category	Control Measure	Primary Pollutant
	PU170	Unpaved Road-Rural Major Coll.	Chemical Stabilization	PM_{10}, $PM_{2.5}$
	PU190	Unpaved Road-Rural Minor Coll.	Chemical Stabilization	PM_{10}, $PM_{2.5}$
	PU210	Unpaved Road - Rural Local	Chemical Stabilization	PM_{10}, $PM_{2.5}$
	PU270	Unpaved Rd-Urban Oth Prin Art.	Hot Asphalt Paving	PM_{10}, $PM_{2.5}$
	PU290	Unpaved Road-Urban Minor Art.	Hot Asphalt Paving	PM_{10}, $PM_{2.5}$
	PU310	Unpaved Road - Urban Collector	Hot Asphalt Paving	PM_{10}, $PM_{2.5}$
	PU330	Unpaved Road - Urban Local	Hot Asphalt Paving	PM_{10}, $PM_{2.5}$
	Pagbu	Agricultural Burning	Bale Stack/Propane Burning	PM_{10}, $PM_{2.5}$
	Pagtl	Agricultural Tilling	Soil Conservation Plans	PM_{10}, $PM_{2.5}$
	Pcatf	Beef Cattle Feedlots	Watering	PM_{10}, $PM_{2.5}$
	Pcnst	Construction Activities	Dust Control Plan	PM_{10}, $PM_{2.5}$
	Ppreb	Prescribed Burning	Increase Fuel Moisture	PM_{10}, $PM_{2.5}$
	Presw	Residential Wood Combustion	Education and Advisory Program	PM_{10}, $PM_{2.5}$
	Point Source SO_2			
*	S00101	Sulf. Acid - Contact Absorber (99.9%)	FGD	SO_2
*	S00201	Sulf. Acid - Contact Absorber (99%)	Dual absorption	SO_2
*	S00202	Sulf. Acid - Contact Absorber (99%)	Dual absorption + FGD	SO_2
*	S00301	Sulf. Acid - Contact Absorber (98%)	Dual absorption	SO_2
*	S00302	Sulf. Acid - Contact Absorber (98%)	Dual absorption + FGD	SO_2
*	S00401	Sulf. Acid - Contact Absorber (97%)	Dual absorption	SO_2
*	S00402	Sulf. Acid - Contact Absorber (97%)	Dual absorption + FGD	SO_2
*	S00501	Sulf. Acid - Contact Absorber (93%)	Dual absorption	SO_2
*	S00502	Sulf. Acid - Contact Absorber (93%)	Dual absorption + FGD	SO_2
*	S00601	Elemental Sulfur Recovery - Claus Stg 2	Amine Scrubbing	SO_2
*	S00602	Elemental Sulfur Recovery - Claus Stg 2	Amine Scrubbing + FGD	SO_2
*	S00701	Elemental Sulfur Recovery - Claus Stg 3 (95-96%)	Amine Scrubbing	SO_2
*	S00702	Elemental Sulfur Recovery - Claus Stg 3 (95-96%)	Amine Scrubbing + FGD	SO_2
*	S00801	Elemental Sulfur Recovery - Claus Stg 3 (96-97%)	Amine Scrubbing	SO_2
*	S00802	Elemental Sulfur Recovery - Claus Stg 3 (96-97%)	Amine Scrubbing + FGD	SO_2
*	S00901	Sulfur Recovery - Sulfur Removal (99%)	FGD	SO_2
*	S01001	Sulfur Recovery - Elemental Sulfur Prodctn.	FGD	SO_2
*	S01101	Inorganic Chemical Manufacture	FGD	SO_2
*	S01201	By-Product Coke Manufacturing	Vacuum Carbonate	SO_2
*	S01301	Process Heaters (Oil and Gas Production)	FGD	SO_2
*	S01401	Primary Metals Industry	FGD	SO_2
*	S01501	Secondary Metal Production	FGD	SO_2
*	S01601	Mineral Products Industry	FGD	SO_2
*	S01701	Pulp and Paper Industry (Sulfate Pulping)	FGD	SO_2
*	S01801	Petroleum Industry	FGD	SO_2
*	S01901	Ind. Boiler Bituminous/Subbituminous Coal	FGD	SO_2
*	S02001	Ind. Boiler Residual Oil	FGD	SO_2
*	S02101	Comm/Inst Boiler - Bituminous/Subbit. Coal	FGD	SO_2
*	S02201	In-process Fuel Use - Bituminous Coal	FGD	SO_2
*	S02301	Industrial Boilers - Lignite	FGD	SO_2
*	S02401	Comm/Inst. Boilers - Residual Oil	FGD	SO_2
*	S02501	Municipal Waste Combustors	FGD	SO_2
*	S02601	Steam Generating Unit-Coal/Oil	FGD	SO_2
*	S02701	Primary Copper Smelters	Dual absorption	SO_2
	Point Source NO_x			
	N01101	ICI Boilers - Coal/Wall	SNCR	NO_x
	N01103	ICI Boilers - Coal/Wall	LNB	NO_x
	N01104	ICI Boilers - Coal/Wall	SCR	NO_x

Table I-1 (continued)

This Report	Measure ID	Source Category	Control Measure	Primary Pollutant
	N01201	ICI Boilers - Coal/FBC	SNCR - Urea	NO_x
	N01301	ICI Boilers - Coal/Stoker	SNCR	NO_x
	N01401	ICI Boilers - Coal/Cyclone	SNCR	NO_x
	N01402	ICI Boilers - Coal/Cyclone	Coal Reburn	NO_x
	N01403	ICI Boilers - Coal/Cyclone	SCR	NO_x
	N01404	ICI Boilers - Coal/Cyclone	NGR	NO_x
	N01501	ICI Boilers - Residual Oil	LNB	NO_x
	N01502	ICI Boilers - Residual Oil	LNB + FGR	NO_x
	N01503	ICI Boilers - Residual Oil	SCR	NO_x
	N01504	ICI Boilers - Residual Oil	SNCR	NO_x
	N01601	ICI Boilers - Distillate Oil	LNB	NO_x
	N01602	ICI Boilers - Distillate Oil	LNB + FGR	NO_x
	N01603	ICI Boilers - Distillate Oil	SCR	NO_x
	N01604	ICI Boilers - Distillate Oil	SNCR	NO_x
	N01701	ICI Boilers - Natural Gas	LNB	NO_x
	N01702	ICI Boilers - Natural Gas	LNB + FGR	NO_x
	N01703	ICI Boilers - Natural Gas	OT + WI	NO_x
	N01704	ICI Boilers - Natural Gas	SCR	NO_x
	N01705	ICI Boilers - Natural Gas	SNCR	NO_x
	N01801	ICI Boilers - Wood/Bark/Stoker	SNCR - Urea	NO_x
	N02001	ICI Boilers - MSW/Stoker	SNCR - Urea	NO_x
	N02101	Internal Combustion Engines - Oil	IR	NO_x
	N02104	Internal Combustion Engines - Oil	SCR	NO_x
	N02201	Internal Combustion Engines - Gas	IR	NO_x
	N02204	Internal Combustion Engines - Gas	AF RATIO	NO_x
	N02207	Internal Combustion Engines - Gas	AF + IR	NO_x
	N02210	Internal Combustion Engines - Gas	L-E (Medium Speed)	NO_x
	N02211	Internal Combustion Engines - Gas	L-E (Low Speed)	NO_x
	N02212	Internal Combustion Engines - Gas	SCR	NO_x
	N02301	Gas Turbines - Oil	Water Injection	NO_x
	N02302	Gas Turbines - Oil	SCR + Water Injecti	NO_x
	N02401	Gas Turbines - Natural Gas	Water Injection	NO_x
	N02402	Gas Turbines - Natural Gas	Steam Injection	NO_x
	N02403	Gas Turbines - Natural Gas	LNB	NO_x
	N02404	Gas Turbines - Natural Gas	SCR + LNB	NO_x
	N02405	Gas Turbines - Natural Gas	SCR + Steam Injecti	NO_x
	N02406	Gas Turbines - Natural Gas	SCR + Water Injecti	NO_x
	N02501	Process Heaters - Distillate Oil	LNB	NO_x
	N02502	Process Heaters - Distillate Oil	LNB + FGR	NO_x
	N02503	Process Heaters - Distillate Oil	SNCR	NO_x
	N02504	Process Heaters - Distillate Oil	ULNB	NO_x
	N02505	Process Heaters - Distillate Oil	SCR	NO_x
	N02506	Process Heaters - Distillate Oil	LNB + SNCR	NO_x
	N02507	Process Heaters - Distillate Oil	LNB + SCR	NO_x
	N02601	Process Heaters - Residual Oil	LNB + FGR	NO_x
	N02602	Process Heaters - Residual Oil	LNB	NO_x
	N02603	Process Heaters - Residual Oil	SNCR	NO_x
	N02604	Process Heaters - Residual Oil	ULNB	NO_x
	N02605	Process Heaters - Residual Oil	LNB + SNCR	NO_x
	N02606	Process Heaters - Residual Oil	SCR	NO_x
	N02607	Process Heaters - Residual Oil	LNB + SCR	NO_x
	N02701	Process Heaters - Natural Gas	LNB	NO_x
	N02702	Process Heaters - Natural Gas	LNB + FGR	NO_x
	N02703	Process Heaters - Natural Gas	SNCR	NO_x
	N02704	Process Heaters - Natural Gas	ULNB	NO_x
	N02705	Process Heaters - Natural Gas	SCR	NO_x
	N02706	Process Heaters - Natural Gas	LNB + SNCR	NO_x
	N02707	Process Heaters - Natural Gas	LNB + SCR	NO_x
	N02801	Adipic Acid Manufacturing	Thermal Reduction	NO_x
	N02802	Adipic Acid Manufacturing	Extended Absorption	NO_x
	N02901	Nitric Acid Manufacturing	Extended Absorption	NO_x
	N02902	Nitric Acid Manufacturing	SCR	NO_x
	N02903	Nitric Acid Manufacturing	SNCR	NO_x
	N03001	Glass Manufacturing - Container	Electric Boost	NO_x
	N03002	Glass Manufacturing - Container	Cullet Preheat	NO_x

Table I-1 (continued)

This Report	Measure ID	Source Category	Control Measure	Primary Pollutant
	N03003	Glass Manufacturing - Container	LNB	NO_x
	N03004	Glass Manufacturing - Container	SNCR	NO_x
	N03005	Glass Manufacturing - Container	SCR	NO_x
	N03006	Glass Manufacturing - Container	OXY-Firing	NO_x
	N03101	Glass Manufacturing - Flat	Electric Boost	NO_x
	N03102	Glass Manufacturing - Flat	LNB	NO_x
	N03103	Glass Manufacturing - Flat	SNCR	NO_x
	N03104	Glass Manufacturing - Flat	SCR	NO_x
	N03105	Glass Manufacturing - Flat	OXY-Firing	NO_x
	N03201	Glass Manufacturing - Pressed	Electric Boost	NO_x
	N03202	Glass Manufacturing - Pressed	Cullet Preheat	NO_x
	N03203	Glass Manufacturing - Pressed	LNB	NO_x
	N03204	Glass Manufacturing - Pressed	SNCR	NO_x
	N03205	Glass Manufacturing - Pressed	SCR	NO_x
	N03206	Glass Manufacturing - Pressed	OXY-Firing	NO_x
	N03301	Cement Manufacturing - Dry	Mid-Kiln Firing	NO_x
	N03302	Cement Manufacturing - Dry	LNB	NO_x
	N03303	Cement Manufacturing - Dry	SNCR - Urea Based	NO_x
	N03304	Cement Manufacturing - Dry	SNCR - NH3 Based	NO_x
	N03305	Cement Manufacturing - Dry	SCR	NO_x
	N03401	Cement Manufacturing - Wet	Mid-Kiln Firing	NO_x
	N03402	Cement Manufacturing - Wet	LNB	NO_x
	N03403	Cement Manufacturing - Wet	SCR	NO_x
	N03501	Iron & Steel Mills - Reheating	LEA	NO_x
	N03502	Iron & Steel Mills - Reheating	LNB	NO_x
	N03503	Iron & Steel Mills - Reheating	LNB + FGR	NO_x
	N03601	Iron & Steel Mills - Annealing	LNB	NO_x
	N03602	Iron & Steel Mills - Annealing	LNB + FGR	NO_x
	N03603	Iron & Steel Mills - Annealing	SNCR	NO_x
	N03604	Iron & Steel Mills - Annealing	LNB + SNCR	NO_x
	N03605	Iron & Steel Mills - Annealing	SCR	NO_x
	N03606	Iron & Steel Mills - Annealing	LNB + SCR	NO_x
	N03701	Iron & Steel Mills - Galvanizing	LNB	NO_x
	N03702	Iron & Steel Mills - Galvanizing	LNB + FGR	NO_x
	N03801	Municipal Waste Combustors	SNCR	NO_x
	N03901	Medical Waste Incinerators	SNCR	NO_x
	N04101	ICI Boilers - Process Gas	LNB	NO_x
	N04102	ICI Boilers - Process Gas	LNB + FGR	NO_x
	N04103	ICI Boilers - Process Gas	OT + WI	NO_x
	N04104	ICI Boilers - Process Gas	SCR	NO_x
	N04201	ICI Boilers - Coke	SNCR	NO_x
	N04203	ICI Boilers - Coke	LNB	NO_x
	N04204	ICI Boilers - Coke	SCR	NO_x
	N04301	ICI Boilers - LPG	LNB	NO_x
	N04302	ICI Boilers - LPG	LNB + FGR	NO_x
	N04303	ICI Boilers - LPG	SCR	NO_x
	N04304	ICI Boilers - LPG	SNCR	NO_x
	N04501	ICI Boilers - Liquid Waste	LNB	NO_x
	N04502	ICI Boilers - Liquid Waste	LNB + FGR	NO_x
	N04503	ICI Boilers - Liquid Waste	SCR	NO_x
	N04504	ICI Boilers - Liquid Waste	SNCR	NO_x
	N04601	IC Engines - Gas, Diesel, LPG	IR	NO_x
	N04604	IC Engines - Gas, Diesel, LPG	SCR	NO_x
	N04701	Process Heaters - Process Gas	LNB	NO_x
	N04702	Process Heaters - Process Gas	LNB + FGR	NO_x
	N04703	Process Heaters - Process Gas	SNCR	NO_x
	N04704	Process Heaters - Process Gas	ULNB	NO_x
	N04705	Process Heaters - Process Gas	SCR	NO_x
	N04706	Process Heaters - Process Gas	LNB + SNCR	NO_x
	N04707	Process Heaters - Process Gas	LNB + SCR	NO_x
	N04801	Process Heaters - LPG	LNB	NO_x
	N04802	Process Heaters - LPG	LNB + FGR	NO_x
	N04803	Process Heaters - LPG	SNCR	NO_x
	N04804	Process Heaters - LPG	ULNB	NO_x
	N04805	Process Heaters - LPG	SCR	NO_x

Table I-1 (continued)

This Report	Measure ID	Source Category	Control Measure	Primary Pollutant
	N04806	Process Heaters - LPG	LNB + SNCR	NO_x
	N04807	Process Heaters - LPG	LNB + SCR	NO_x
	N04901	Process Heaters - Other Fuel	LNB + FGR	NO_x
	N04902	Process Heaters - Other Fuel	LNB	NO_x
	N04903	Process Heaters - Other Fuel	SNCR	NO_x
	N04904	Process Heaters - Other Fuel	ULNB	NO_x
	N04905	Process Heaters - Other Fuel	LNB + SNCR	NO_x
	N04906	Process Heaters - Other Fuel	SCR	NO_x
	N04907	Process Heaters - Other Fuel	LNB + SCR	NO_x
	N05001	Gas Turbines - Jet Fuel	Water Injection	NO_x
	N05002	Gas Turbines - Jet Fuel	SCR + Water Injection	NO_x
	N05401	Space Heaters - Distillate Oil	LNB	NO_x
	N05402	Space Heaters - Distillate Oil	LNB + FGR	NO_x
	N05403	Space Heaters - Distillate Oil	SCR	NO_x
	N05404	Space Heaters - Distillate Oil	SNCR	NO_x
	N05501	Space Heaters - Natural Gas	LNB	NO_x
	N05502	Space Heaters - Natural Gas	LNB + FGR	NO_x
	N05503	Space Heaters - Natural Gas	OT + WI	NO_x
	N05504	Space Heaters - Natural Gas	SCR	NO_x
	N05505	Space Heaters - Natural Gas	SNCR	NO_x
	N05601	Ammonia - NG-Fired Reformers	LNB	NO_x
	N05602	Ammonia - NG-Fired Reformers	LNB + FGR	NO_x
	N05603	Ammonia - NG-Fired Reformers	OT + WI	NO_x
	N05604	Ammonia - NG-Fired Reformers	SCR	NO_x
	N05605	Ammonia - NG-Fired Reformers	SNCR	NO_x
	N05801	Lime Kilns	Mid-Kiln Firing	NO_x
	N05802	Lime Kilns	LNB	NO_x
	N05803	Lime Kilns	SNCR - Urea Based	NO_x
	N05804	Lime Kilns	SNCR - NH3 Based	NO_x
	N05805	Lime Kilns	SCR	NO_x
	N05901	Comm./Inst. Incinerators	SNCR	NO_x
	N06001	Indust. Incinerators	SNCR	NO_x
	N06101	Sulfate Pulping - Recovery Furnaces	LNB	NO_x
	N06102	Sulfate Pulping - Recovery Furnaces	LNB + FGR	NO_x
	N06103	Sulfate Pulping - Recovery Furnaces	OT + WI	NO_x
	N06104	Sulfate Pulping - Recovery Furnaces	SCR	NO_x
	N06105	Sulfate Pulping - Recovery Furnaces	SNCR	NO_x
	N06202	Ammonia Prod; Feedstock Desulfurization	LNB + FGR	NO_x
	N06302	Plastics Prod-Specific; (ABS) Resin	LNB + FGR	NO_x
	N06402	Starch Mfg; Combined Operations	LNB + FGR	NO_x
	N06503	By-Product Coke Mfg; Oven Underfiring	SNCR	NO_x
	N06602	Pri Cop Smel; Reverb Smelt Furn	LNB + FGR	NO_x
	N06703	Iron Prod; Blast Furn; Blast Htg Stoves	LNB + FGR	NO_x
	N06802	Steel Prod; Soaking Pits	LNB + FGR	NO_x
	N06902	Fuel Fired Equip; Process Htrs; Pro Gas	LNB + FGR	NO_x
	N07001	Sec Alum Prod; Smelting Furn/Reverb	LNB	NO_x
	N07101	Steel Foundries; Heat Treating Furn	LNB	NO_x
	N07201	Fuel Fired Equip; Furnaces; Natural Gas	LNB	NO_x
	N07301	Asphaltic Conc; Rotary Dryer; Conv Plant	LNB	NO_x
	N07401	Ceramic Clay Mfg; Drying	LNB	NO_x
	N07503	Coal Cleaning-Thrml Dryer; Fluidized Bed	LNB	NO_x
	N07603	Fbrglass Mfg; Txtle-Type Fbr; Recup Furn	LNB	NO_x
	N07702	Sand/Gravel; Dryer	LNB + FGR	NO_x
	N07802	Fluid Cat Cracking Units; Cracking Unit	LNB + FGR	NO_x
	N07901	Conv Coating of Prod; Acid Cleaning Bath	LNB	NO_x
	N08012	Natural Gas Prod; Compressors	SCR	NO_x
	N08103	In-Process; Bituminous Coal; Cement Kiln	SNCR - urea based	NO_x
	N08203	In-Process; Bituminous Coal; Lime Kiln	SNCR - urea based	NO_x
	N08301	In-Process Fuel Use;Bituminous Coal; Gen	SNCR	NO_x
	N08402	In-Process Fuel Use; Residual Oil; Gen	LNB	NO_x
	N08501	In-Process Fuel Use; Natural Gas; Gen	LNB	NO_x
	N08602	In-Proc;Process Gas;Coke Oven/Blast Furn	LNB + FGR	NO_x
	N08701	In-Process; Process Gas; Coke Oven Gas	LNB	NO_x
	N08801	Surf Coat Oper;Coating Oven Htr; Nat Gas	LNB	NO_x
	N08901	Solid Waste Disp; Gov; Other Incin; Sludge	SNCR	NO_x

Table I-1 (continued)

This Report	Measure ID	Source Category	Control Measure	Primary Pollutant
		Area Source NO$_x$		
	N10001	Industrial Coal Combustion	RACT to 50 tpy (LNB)	NO$_x$
	N10002	Industrial Coal Combustion	RACT to 25 tpy (LNB)	NO$_x$
	N10101	Industrial Oil Combustion	RACT to 50 tpy (LNB)	NO$_x$
	N10102	Industrial Oil Combustion	RACT to 25 tpy (LNB)	NO$_x$
	N10201	Industrial NG Combustion	RACT to 50 tpy (LNB)	NO$_x$
	N10202	Industrial NG Combustion	RACT to 25 tpy (LNB)	NO$_x$
	N12201	Open Burning	Episodic Ban (Daily Only)	NO$_x$
	N13201	Agricultural Burning	Seasonal Ban (Ozone Season)	NO$_x$
		Point Source VOC		
	V0171	Terephthalic Acid Manufacture	Incineration	VOC
	V0211	Cellulose Acetate Manufacture	Carbon Adsorption	VOC
	V0281	Vegetable Oil Manufacture	Stripper and Equipment	VOC
	V0321	Carbon Black Manufacture	Flare	VOC
	V0349	Beverage Can Coating	Incineration	VOC
	V0389	Plastic Parts Coating	Incineration	VOC
	V0399	Wood Furniture Coating	Incineration	VOC
	V0529	Aircraft Surface Coating	Incineration	VOC
	V0531	Whiskey Fermentation - Aging	Carbon Adsorption	VOC
	V0541	Charcoal Manufacturing	Incineration	VOC
	V0561	SOCMI - Reactor Processes	New CTG level control	VOC
	V0571	SOCMI - Distillation	New CTG level control	VOC
	V0951	Bakeries	Incineration at Oven Vent	VOC
	V0961	Urea Resins - General	RACT Extended to Other Areas	VOC
	V0971	Organic Acids Manufacture	RACT Extended to Other Areas	VOC
	V0981	Leather Products	RACT Extended to Other Areas	VOC
	V1089	Fabric Coating	Incineration	VOC
	V1701	Service Stations- Stage I	Vapor Balance	VOC
	V1801	Printing - Letterpress	Carbon Adsorption	VOC
	V1821	Printing - Lithographic	New CTG to Other Areas	VOC
		Area Source VOC		
	V21101	Dry Cleaning - perc	MACT (condensers/adsorbers)	VOC
	V21201	Dry cleaning - petroleum	MACT	VOC
	V21701	Bulk Terminals	Balanced/Adsorber/Testing	VOC
	V22001	Architectural coatings	AIM Coating Federal Rule	VOC
	V22002	Architectural coatings	South Coast Phase I	VOC
	V22003	Architectural coatings	South Coast Phase II	VOC
	V22004	Architectural coatings	South Coast Phase III	VOC
	V22101	Traffic markings	AIM Coating Federal Rule	VOC
	V22102	Traffic markings	South Coast Phase I	VOC
	V22103	Traffic markings	South Coast Phase II	VOC
	V22104	Traffic markings	South Coast Phase III	VOC
	V22201	Industrial maintenance coating	AIM Coating Federal Rule	VOC
	V22202	Industrial maintenance coating	South Coast Phase I	VOC
	V22203	Industrial maintenance coating	South Coast Phase II	VOC
	V22204	Industrial maintenance coating	South Coast Phase III	VOC
	V22301	Metal coil & can coating	MACT	VOC
	V22302	Metal coil & can coating	BAAQMD Rule 11 Amended	VOC
	V22303	Metal coil & can coating	Incineration	VOC
	V22501	Wood furniture surface coating	MACT	VOC
	V22502	Wood furniture surface coating	New CTG	VOC
	V22503	Wood furniture surface coating	Add-On Controls	VOC
	V22601	Adhesives - industrial	SCAQMD Rule 1168	VOC
	V23201	Open top degreasing	MACT	VOC
	V23202	Open top degreasing	SCAQMD 1122 (VOC content limit)	VOC
	V23203	Open top degreasing	Airtight degreasing system	VOC
	V24001	Paper surface coating	Incineration	VOC
	V24101	Cold cleaning	NESHAP/MACT	VOC
	V24102	Cold cleaning	SCAQMD 1122 (VOC content limit)	VOC
	V24103	Cold cleaning	Airtight degreasing system	VOC
	V24401	Rubber and plastics mfg	SCAQMD - low VOC	VOC
	V24501	Metal furn, appliances, parts	MACT	VOC

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Table I-1 (continued)

This Report	Measure ID	Source Category	Control Measure	Primary Pollutant
	V24502	Metal furn, appliances, parts	SCAQMD Limits	VOC
	V24601	Automobile refinishing	Federal Rule	VOC
	V24602	Automobile refinishing	CARB BARCT limits	VOC
	V24603	Automobile refinishing	FIP Rule (VOC content & TE)	VOC
	V24701	Machn, electric, railroad ctng	MACT level of control	VOC
	V24702	Machn, electric, railroad ctng	SCAQMD Limits	VOC
	V24803	Aerosols	CARB Tier 2 standards - reform	VOC
	V24901	Consumer solvents	Federal Consumer Solvents Rule	VOC
	V24902	Consumer solvents	CARB mid-term limits	VOC
	V24903	Consumer solvents	CARB long-term limits	VOC
	V25001	Aircraft surface coating	MACT	VOC
	V25101	marine surface coating	MACT	VOC
	V25102	marine surface coating	Add-on control levels	VOC
	V25301	Electrical/electronic coating	MACT	VOC
	V25302	Electrical/electronic coating	SCAQMD Rule	VOC
	V25401	Motor vehicle coating	MACT	VOC
	V25402	Motor vehicle coating	Incineration	VOC
	V25901	SOCMI batch reactor processes	New CTG	VOC
	V26602	Open burning	Episodic ban	VOC
	V26901	Commercial adhesives	Federal Consumer Solvents Rule	VOC
	V26902	Commercial adhesives	CARB mid-term limits	VOC
	V26903	Commercial adhesives	CARB long-term limits	VOC
	V27003	TSDFs	Phase I & II rules	VOC
	V27102	Bakeries	Incineration >100,000 lbs brea	VOC
	V27201	Cutback Asphalt	Switch to emulsified asphalts	VOC
	V27401	SOCMI fugitives	Equipment and maintenance	VOC
	V27601	Petroleum refinery fugitives	Equipment and maintenance	VOC
	V27702	Pharmaceutical manufacture	RACT	VOC
	V27801	Synthetic fiber manufacture	Carbon adsorber	VOC
	V27901	Oil and natural gas production	Equipment and maintenance	VOC
	V28001	Stage I-truck unloading	Vapor balance	VOC
	V28003	Stage I-truck unloading	Vapor balance + P/V valves	VOC
	V28401	Municipal solid waste landfill	RCRA standards	VOC
	V28501	Web Offset Lithography	New CTG	VOC
	V29502	Pesticide Application	Reformulation - FIP rule	VOC
	V22401	Wood product surface coating	MACT	VOC
	V22402	Wood product surface coating	SCAQMD Rule 1104	VOC
	V22403	Wood product surface coating	Incineration	VOC
Utility Boilers				
	PUTIL	Utility Boilers	Fabric Filter	PM_{10}, $PM_{2.5}$
	SUTIL	Utility Boilers	FGD Scrubber	SO_2
	N00101	Utility Boilers	SCR	NO_x
Nonroad Engines				
	PHDRET	Nonroad Diesel Engines	Heavy Duty Retrofit Program	PM_{10}
	VNRFG	Nonroad Gasoline Engines	Federal Reformulated Gasoline	VOC
Highway Vehicles				
	mOT1	Highway Vehicles - LD Gas Trucks	Tier 2 Standards	VOC, NO_x
	mOT2	Highway Vehicles - Gasoline	Federal Reformulated Gasoline	VOC, NO_x
	mOT3	Highway Vehicles - LD Gasoline	High Enhanced I/M	NO_x, VOC
	mOT4	Highway Vehicles - LD Gasoline	Fleet ILEV	VOC
	mOT5	Highway Vehicles - HD Diesels	HDDV Retrofit Program	PM_{10}
	mOT6	Highway Vehicles - Gasoline	Transportation Control Package	NO_x, VOC

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CHAPTER II
EVALUATION OF CONTROL MEASURES FOR STATIONARY VOC SOURCE CATEGORIES

This chapter evaluates potential source control measures for point and area source VOC emitters. Table I-1 presents a complete list of control measures incorporated into ControlNET, differentiating between measures that are documented in this report and measures documented in previous reports. This chapter identifies the newly developed control measures, as well as revisions to measures developed in previous analyses. The general impetus for these revisions is the availability of new information.

Area source measures that control VOCs are described first, followed by point source control measures for VOC. Each subsection briefly describes the source category, available control techniques, and the control options selected for the analysis. The discussion of the control options selected for the analysis includes an evaluation of emission reductions and total annualized costs. Capital and operation and maintenance (O&M) costs are discussed for those measures for which information was identified to estimate these costs.

A. AREA SOURCE VOC CONTROL MEASURES

This section discusses area source control measures for VOC. The penetration rate, which is an estimate of the fraction of emissions covered by each measure, accounts for source size cutoffs and other exemptions from regulation. For most area source measures, the penetration rate is included within the control measure efficiency.

1. Architectural and Industrial Maintenance (AIM) Coatings

Section 183 of the CAA requires EPA to list for regulation products within the consumer and commercial (C&C) products category that account for at least 80 percent of VOC emissions from this category in ozone nonattainment areas. In 1995, EPA completed a report to Congress which prioritized into groups the products that would be subject to regulation (EPA, 1995a). The AIM coatings source category is in the first grouping of C&C products to be regulated because it is one of the largest product categories, accounting for about 9 percent of the VOC emissions from all C&C products (60FR15264, 1995). AIM coatings are used by contractors, industry, and households, and include: interior and exterior paints, industrial maintenance coatings, wood finishes, cement coatings, roof coatings, traffic marking paints, and specialty coatings. Area source emissions for AIM coatings are generally classified under Source Classification Code (SCC) 2401001000 (architectural coatings), SCC 2401100000 (industrial maintenance coatings), and SCC 2401008000 (traffic markings).

a. Description of Available Control Options

AIM coatings are formulated with a variety of components including pigments, resins, solvents, and different additives such as driers, anti-skinning agents, anti-sag agents, dispersing agents, defoaming agents, preservatives, and fungicides. The primary source of emissions from AIM coatings is the solvent component. Add-on control equipment is not a feasible control option for AIM coatings because the application of these products involves a large number of primarily small, widespread emission sources. Reductions in VOC emissions from AIM coatings are currently achieved in a number of States through the use of product reformulation, product substitution, and the education of consumers about the availability of low-VOC coatings (STAPPA/ALAPCO, 1993).

i. Federal Rule

The EPA proposed a national rule for reducing VOC emissions from specific types of AIM coatings (61FR32729, 1996). The proposed rule, which provides uniformity over the State-level

content limits that AIM coating manufacturers must meet, was expected to go into effect on April 1, 1997. The final rule was promulgated in August of 1998, with compliance required one year after promulgation. The proposed Federal rule is expected to reduce VOC emissions by 20 percent from 1990 levels (EPA, 1995a).

The proposed rule sets maximum allowable VOC content limits for 55 different categories of AIM coatings, and would affect the manufacturers and importers of the coating products. The EPA identified two options for manufacturers of AIM coatings to reduce VOC emissions: reformulate the coating to increase the solids-to-solvent ratio, or reformulate the coating by substituting water for an organic solvent (EPA, 1995a). The EPA estimated the cost of reformulating noncompliant coatings based on information provided by industry representatives during the regulatory negotiation process. Industry representatives estimated the level of effort required by a representative firm to research and develop a new prototype coating to be 2.5 scientist-years over a 3-year time period. Based on an assumed cost of $100,000 per scientist-year over 2.5 years, EPA calculated an annualized cost of $17,772 (1991 dollars) per reformulation (61FR32729, 1996). The EPA developed an aggregate cost-effectiveness value of $237/ton (1991 dollars), using the estimated emission reduction of 106,000 tons of VOC per year. The EPA's cost analysis does not include estimates of changes in equipment, materials, or labor costs associated with product reformulation. In 1990 dollar terms, the cost effectiveness of the Federal rule is $228 per ton.[1] For the final rule, EPA estimated the total annualized cost of roughly $32 million (in 1996 dollars) and the cost effectiveness of $250 per ton (EPA, 1998a).

In its analysis of the proposed Federal rule, EPA assumed that the cost of product reformulation would bring the VOC content limit for each noncompliant coating down to the level of the standards. The EPA, however, noted the likelihood that some manufacturers will likely reduce the VOC content of their coatings to levels significantly below the limits in the rule (EPA, 1996a). The "at-the-limit" assumption, therefore, likely results in emission reductions being understated. The EPA did not account for potential cost differences for reformulating coatings to various content limits. Instead, EPA assumed that a reformulation has a certain cost to manufacturers regardless of the target content limit, or the anticipated VOC reduction (Ducey, 1997). In its cost analysis, insufficient data were available for EPA to distinguish reformulation costs between different coating types (i.e., the reformulation cost for flat paints is equal to the reformulation cost for all other affected paint types). The EPA noted the likelihood of reformulation costs varying from product to product (EPA, 1995b).

ii. California Regulations

In 1989, the California Air Resources Board (CARB) adopted a model architectural coatings rule for use by California jurisdictions in developing their architectural coatings rules. In most cases, the Federal VOC limits are equal to or less stringent than the limits in CARB's model rule. CARB's estimated cost-effectiveness values range from a savings of $8,600 per ton (for pool finishes) to a cost of $12,800 per ton of VOC reduced (for specialty enamels) (CARB, 1989). The cost differential is attributable to the wide diversity of coatings and uncertainty about the necessary equipment modifications associated with coating reformulation. In CARB's cost analysis, quantifiable cost factors included price changes and raw material costs. Factors that were not quantified in the cost analysis included: research and development costs, costs associated with increased surface preparation, and any necessary training costs for using the reformulated coatings.

To date, 16 of California's air quality districts have adopted architectural coatings rules (Jaczola, 1997). The architectural coatings rule, originally adopted by the South Coast Air Quality Management District (SCAQMD) in 1977 (and amended several times since), is the most stringent in California. In its most recent air quality management plan, the SCAQMD outlines a two-phase approach for obtaining further reductions from this source category. Phase I is a recently adopted amendment to SCAQMD's existing architectural coatings rule that establishes more stringent VOC content limits for flat, multi-color, traffic, and lacquer coatings. Phase II represents an effort to lower the VOC content limits for non-flat industrial maintenance primers and topcoats, sealers, undercoaters, and quick-dry enamels. Phase I is expected to result in a VOC emission reduction of 17.5 percent, and Phase II is expected to achieve an

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[1]The 1991:1990 producer price index for SIC code 2851 was applied to the 1991 cost-effectiveness value to convert to 1990 dollars (BLS, 1996).

additional 32 percent reduction in VOC emissions by 2008, for an overall emission reduction of nearly 50 percent beyond SCAQMD's previous architectural coatings rule (SCAQMD, 1996a). Most recently, SCAQMD has adopted a three phase (rather than two) approach to amending AIM coating rules.

For the Phase I amendment, a SCAQMD report documents cost per gallon, total annual cost, emission reduction and cost-effectiveness values for each of the four regulated coating types (SCAQMD, 1996b). Cost data for Phase II controls are sparse and not well-documented. The 1997 air quality management plan cites a cost effectiveness of $12,300 per ton of VOC reduced; however, documentation of this estimate is not available. It was determined that this estimate should be considered speculative because cost data have not been developed for the individual coating categories to be covered by this measure. The South Coast notes that the process of collecting reformulation cost data for these categories is very complex due to the resin technology used in lower-VOC, high-performance industrial maintenance coatings (silicone-based resins, or polyurethanes) and the number of resin systems involved (Berry, 1997).

The SCAQMD Governing Board adopted further amendments to its architectural coatings rule (Rule 1113) at its May 14, 1999 meeting (SCAQMD, 1999a). The amendments (phase 2 of planned revisions) will require further reformulations in two steps, first by July 2002, and then again by July 2006, subject to studies of technical feasibility for the various paint categories covered. When fully effective, the new requirements are expected to result in reductions of 34 percent from baseline levels. Additional amendments (phase 3) are planned in the next decade to further reduce emissions by about 24 percent.

b.   Control Options Selected for Analysis

For the CAA baseline, a 20 percent control effectiveness is assumed for the proposed Federal AIM coatings rule. Based on an assessment of available cost data for modeling control options beyond the baseline, it was determined that sufficient data are available from SCAQMD to model the Phase I amendment for flat, multi-color, traffic, and lacquer coatings. The SCAQMD documentation for the Phase I amendment contains detailed information on the incremental costs for tightening limits for the affected coating types beyond the limits established by the proposed Federal rule (SCAQMD, 1996b). The Phase 2 amendment is also included as an additional control measure with the recently available information from the South Coast. Phase 3 reductions are also included; however, reduction and cost data are highly uncertain.

The SCAQMD has identified the cost increase for different paint types associated with its current architectural coatings content limits. For the coating types covered by the SCAQMD Phase I amendment, the current SCAQMD coating limits are the same as the limits in the Federal rulemaking. The content limits in the SCAQMD Phase I amendment are phased-in, and are specified in terms of near-term limits, and future effective limits. Based on cost estimates from paint manufacturers, SCAQMD developed per gallon costs of compliance with the near-term and future effective limits for lacquers and flat paints. The SCAQMD estimated that manufacturers would use an acetone formulation with an associated cost of $2 per gallon to meet the proposed 550 grams per liter (g/L) VOC limit for lacquers. To comply with a future effective standard of 275 g/L VOC limit for lacquers, the SCAQMD estimated that manufacturers would use water-borne reformulations at an estimated cost of $4 per gallon. This cost estimate is based on EPA's Wood Coatings National Emission Standard for Hazardous Air Pollutants (NESHAP) analysis (SCAQMD, 1996b; Berry, 1997). For flats, South Coast estimated a zero cost for complying with the near-term 100 g/L limit since most flats sold in California are already in compliance with this limit. For the future effective limit of 50 g/L, South Coast estimated an incremental cost of $4 per gallon based on data supplied by paint manufacturers (SCAQMD, 1996b). The South Coast later determined that flat paints were being reformulated at a lower cost, but maintained the original $4 per gallon estimate as a worst-case scenario in its cost-effectiveness calculation. (The SCAQMD also noted that the $4 per gallon estimate is supported by an estimate developed by New York's INFORM group.)

These cost estimates represent the incremental cost of reformulating flats and lacquers from the initial SCAQMD limits (equivalent to the limits in the proposed Federal rule) to the Phase I SCAQMD limits. For the remaining two coating types regulated by the amendment (multi-color and traffic coatings), the SCAQMD estimated that a cost savings was likely to be associated with reformulation due to a decrease in the cost of input materials. (The estimated

magnitude of the savings is not documented.) These per gallon costs were used as the basis for calculating a cost effectiveness for the control option being modeled in this analysis. Because flats and lacquers comprise 88 percent of paint sales for the categories covered by the SCAQMD Phase I amendment, the omission of multi-color and traffic coatings from the cost-effectiveness calculation is not expected to greatly impact the estimate developed for this analysis.

For each coating type and content limit, the required reduction in VOC content was calculated. Based on the assumption that all VOCs would evaporate, the emission reduction was calculated by converting the reduction per gallon to total tons reduced using national sales data by paint type (EPA, 1996a). Costs were estimated by multiplying the cost per gallon data described above to total gallons sold. These calculations result in cost-effectiveness values ranging from $3,300 to $4,600 per ton depending on the specified limit and paint type. A weighted average cost effectiveness of $4,500 per ton (1995 dollars) was calculated for this analysis based on national sales data by paint type (EPA, 1996a). This value was converted to 1990 dollars using the 1995:1990 producer price index for Standard Industrial Classification (SIC) code 2851 (Paints and Allied Products), resulting in a cost-effectiveness estimate of $3,940 per ton (BLS, 1996).

For the phase 2 amendments, the SCAQMD completed a socioeconomic impact assessment (SCAQMD, 1999a). Staff conservatively assumed a 10 percent price increase per gallon for compliant coatings meeting the interim standards in 2002 and a 20 percent increase for compliant coatings meeting the final limits in 2006. It is assumed that the increase will continue to 2015 for the final compliance data coatings, recognizing the fact that reformulation is typically a one-time investment whose useful life goes beyond the year in which reformulation occurs. The overall cost-effectiveness of the proposed amendments (total costs/total reductions) over the years 2002-2015, is estimated to be $13,317 per ton. Costs vary significantly among individual coatings categories.

Phase 3 amendments are projected to achieve an additional 24 percent reduction. There is currently no cost data available for the phase 3 amendments. The highest incremental cost effectiveness estimate for any individual product for the phase 2 amendments is $26,000 per ton (1998 dollars). This is about double the average phase 2 cost. This estimate will be used to model phase 3 reductions. This cost estimate is highly uncertain as no specific cost data are available. CARB is currently funding a study to examine zero-polluting stains, waterproofing sealers, and clear wood finishes which will be used to comply with the third phase emission reductions.

i. Emission Reduction

A summary of the emission reductions by measure for AIM coatings is shown in Table II-1.

ii. Annual Costs

The estimated incremental cost effectiveness and overall cost effectiveness for each measure is shown in Table II-2.

Table II-1
Summary of AIM Coating Control Measure Reductions

Rule	Overall Reduction (%)*
Federal AIM	20
SCAQMD Phase I	34
SCAQMD Phase II	47
SCAQMD Phase III	73

NOTE: *Phase I is incremental reduction of 17.5% from baseline (Federal AIM); phase II is a 34% reduction from baseline; phase III is an additional 24 percent reduction from phase II.

Table II-2
Summary of AIM Coating Control Measure Cost Effectiveness

Rule	Incremental Cost Effectiveness	Overall Cost Effectiveness
Federal AIM	$228	$228
SCAQMD Phase I	$3,179	$1,443
SCAQMD Phase II	$10,746	$4,017
SCAQMD Phase III	$20,981	$10,059

NOTE: 1990 dollars.

Because capital cost information was not available, capital costs were not estimated for this analysis.

It is important to highlight the fact that areas of uncertainty exist in determining the costs for additional AIM coating regulations. First, it is difficult to quantify the extent to which the Federal rule may result in coatings with VOC contents that are lower than the levels specified in the proposed rule. In these cases, the incremental cost of achieving a tightened standard may approach zero. Also, there are a number of quality considerations related to reformulating AIM coatings that may affect the feasibility of achieving tightened standards. The paint manufacturing industry has expressed concerns about the inability of some low-VOC coatings to meet performance requirements that can be met by high-VOC coatings, and the undesirable qualities of some low-VOC coatings, including longer drying times or the need for more thorough surface preparation.

2.   Consumer Products

Section 183(e) of the CAA requires EPA to regulate VOC emissions from C&C products. In 1990, the C&C products source category accounted for approximately 6 million tons of VOC, or about 28 percent, of all anthropogenic VOC emissions (60FR15264, 1995). In its schedule for regulating the category, EPA divided the C&C category into four groups. In addition to AIM coatings, the consumer products source category is a component of the first group to be regulated under Section 183(e) of the CAA. Consumer products include (but are not limited to): personal care products, household cleaners and disinfectants, automotive aftermarket products, adhesives and sealants, lawn and garden products, and household insecticides. The 24 types of products covered by EPA's 1996 proposed consumer products rule accounted for 331,000 tons of VOC emissions in 1990 (60FR15264, 1995). The final rule for household consumer products was promulgated in August of 1998.

For this analysis, control measures options were evaluated for the consumer solvents source category. Consumer solvent emissions are classified under the following SCCs:

- 2461600000:   Miscellaneous Non-Industrial: Commercial - Adhesives and Sealants
- 2461850000:   Miscellaneous Non-Industrial: Commercial - Pesticide Application
- 2465000000:   Miscellaneous Non-Industrial: Consumer - All Products/Processes
- 2465100000:   Miscellaneous Non-Industrial: Consumer - Personal Care Products
- 2465200000:   Miscellaneous Non-Industrial: Consumer - Household Products
- 2465400000:   Miscellaneous Non-Industrial: Consumer - Automotive Aftermarket Products
- 2465600000:   Miscellaneous Non-Industrial: Consumer - Adhesives and Sealants
- 2465900000:   Miscellaneous Non-Industrial: Consumer - Miscellaneous Products - Not Elsewhere Classified
- 2495000000:   All Solvent User Groups

a.   Description of Available Control Options

Existing and proposed State and Federal regulations for consumer products limit the VOC content of specific product types. Potential control techniques for consumer products include product reformulation, repackaging, and product substitution. In its cost analysis of consumer product regulations, CARB determined that product reformulation is the most likely

means of meeting VOC limits (CARB, 1990). Several methods are available to reformulate products, including the partial or complete replacement of VOC solvents with water or other non- or low-VOC compounds.

i. Federal Rule

In April 1996, EPA proposed a consumer products rule, which reduced the inconsistency associated with the limits that had been adopted by individual States (61FR14531, 1996). The final rule was promulgated in August of 1998 (EPA, 1998b). The Federal rule covers those consumer products that EPA determined to be most amenable to regulation, and were capable of achieving significant VOC reductions without significant effects on product quality or price (EPA, 1995b). The proposed rule sets maximum allowable VOC content limits for 24 consumer product categories. The EPA estimates a 20 percent reduction in VOC emissions from the proposed consumer products rule (61FR14531, 1996). The EPA developed a cost-effectiveness value (in 1991 dollars) for the consumer products rule of $237 per ton of VOC reduced (EPA, 1996b). In 1990 dollar terms, the cost effectiveness of the Federal rule is $232 per ton.[2] The Federal rule required companies to do what they (in most cases) had already done to comply with CARB's and other States' rules in existence before EPA's efforts. The cost data developed by EPA does not allow for estimation of the costs of limits more stringent than those in the proposed rule (Moore, 1997).

ii. California Regulations

The CARB plans to reduce VOC emissions from the consumer products category using three types of control measures: *near-term, mid-term,* and *long-term* measures. *Near-term* measures include VOC content limits for antiperspirants, Phase I consumer products, and Phase II consumer products. The CARB is implementing the *near-term* measures as follows:

1) Initial VOC limits for:
   Antiperspirants by 1993,
   Phase I consumer products by 1994, and
   Phase II consumer products by 1995;

2) More stringent VOC content limits for:
   Antiperspirants by 1999,
   Selected Phase I products by 1996 and 1999, and
   Selected Phase II products by 1997 and 1998.

In its Federal rule, EPA essentially proposed CARB's initial VOC limits for antiperspirants, Phase I consumer products, and Phase II consumer products. In total, CARB expects to achieve a 30 percent VOC reduction in 1990 Statewide emissions for *near-term* measures by 1999. The estimated cost effectiveness for its *near-term* measures vary by product type, and range from a savings of $100 per ton to a cost of $2,100 per ton of VOC reduced (CARB, 1991). This range is based on cost-effectiveness estimates for five product type categories with different cost input assumptions and amortization periods.

Some of CARB's standards were identified as technology-forcing because they cannot be met by manufacturers at the time of rule adoption, but can be met within the time-frame provided by the regulation. At the time CARB was developing its rules, it did not have the resources to research the costs associated with reformulating each of the individual consumer products. Because the hairspray rule was controversial, CARB undertook an analysis to evaluate the ability of manufacturers to meet the *near-term* hairspray standard (CARB, 1997a). The CARB analysis of the hairspray manufacturing industry estimated an incremental cost-effectiveness range of $1,000

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[2]The cost estimate in the Federal rule was converted from 1991 dollars to 1990 dollars using the producer price index for SIC code 284 (BLS, 1996).

to $7,600 per ton. This cost-effectiveness range corresponds to the cost associated with the tightening of the current standard (80 percent VOC content) to the future standard (55 percent VOC content). The CARB does not plan on conducting in-depth studies of reformulating additional product types, since the results of the hairspray analysis are reasonably close to CARB's original cost estimates for reformulating a broad range of consumer product types (Billington, 1997).

The CARB's *mid-term* controls (Phase III) apply to additional consumer products that are not affected by the *near-term* measures. These measures are to achieve an additional 25 percent reduction in overall VOC emissions from consumer products by 2005. In 1997, CARB addressed the first round of mid-term measures, referred to as mid-term I. In September of 1999, CARB proposed additional amendments for consideration by the Air Resources Board, referred to as mid-term II. These will be considered by the Air Resources Board on October 28, 1999. The CARB's long-term measures depend on future technological innovation and market incentive methods that can be developed and implemented before 2010. CARB hopes to achieve an additional 30 percent reduction from these measures, bringing total reductions to 85 percent (CARB, 1997; 1999a).

b.   Control Options Selected for Analysis

ControlNET will include a 20 percent control effectiveness in the baseline based on the Federal consumer products rule. After assessing the available cost data for modeling control levels beyond the baseline, the additional options include: CARB's near-term limits, CARB's mid-term measures, and CARB's long-term measure.

i.   Emission Reduction

CARB's near-term measures are slightly more stringent than the Federal rule for some products. CARB's near-term measures are expected to result in an overall reduction of 30 percent, compared to the 20 percent reduction for the Federal rule.

CARB's mid-term measures are expected to result in an additional 25 percent reduction, bringing the total reduction to 55 percent. Mid-term I (plus other amendments for specific products) brought estimated reductions to 40 percent. The mid-term II regulations would reduce emissions of regulated products by about 50 percent. Regulated products contribute approximately 20 percent of total consumer emissions in 1994. Because CARB has implemented regulations in phases and reductions are sometimes expressed with respect to different baselines (1990 versus 1994 versus 1997), it is difficult to determine the reduction from "uncontrolled" emissions for each phase of regulation. Based on CARB's commitment, the following layers of measures will be modeled:

Measure	Overall Reduction
Federal AIM	20 percent
CARB Mid-term	55 percent
CARB Long-term	85 percent

ii.   Annual Costs

The Federal consumer solvents rule is estimated to have an average cost effectiveness of $232 per ton (1990 dollars). Table II-3 presents estimates of the cost-effectiveness of CARB's consumer products regulations. All costs are in 1997 dollars.

Table II-3
Cost Effectiveness of CARB Consumer Product Regulations

Year	Regulation/Control Measure	Cost-Effectiveness ($/Pound (lb) of VOC Reduced)	Average $/lb
1989	Antiperspirants and Deodorants	$0.54-$1.30	$0.92
1990	Phase I Consumer Products	Net savings to $1.80	$0.90
1992	Phase II Consumer Products	<$0.01 to $1.10	$0.55
1995	Aerosol Coating Products	$2.85 to $3.20	$3.03
1997	Hairspray	$2.10 to $2.50	$2.25
1997	Mid-Term I Consumer Products	$0.00 to $7.10	$0.25
1999	Mid-Term II Consumer Products	$0.00 to $6.30	$0.40

Based on the emission reductions for each regulation, the overall cost effectiveness of CARB's mid-term limits measure (includes all limits for near-term and mid-term) is estimated at $2,340 per ton. In 1990 dollars, this is $2,129 per ton.

There currently is no information available on the cost of the long-term consumer products commitment. An incremental cost per ton of $4,680 is assumed, double the average cost through the mid-term limits. In 1990 dollars, this is $4,257 per ton. Overall cost effectiveness for this measure (combining near-term, mid-term, and long-term) is $2,880 per ton of VOC reduced.

It should be noted that CARB expects costs to be incurred only through the first 15 years or so of regulation, due to research and development and changes to production lines.

iii.   Capital Costs

Capital costs were not estimated for this analysis because capital cost information was not available. The Federal rule indicates that there are virtually no capital costs associated with the final rule, except for the development of new, reformulated products.

3.   Industrial Surface Coating

This category covers the small industrial surface coating facilities not captured in the point source inventory. The categories, along with information on CAA requirements, are shown in Table II-4. Measures beyond CAA requirements that were developed under prior modeling efforts are shown in Table II-5.

The following subsections address control measure options by individual source category. This is followed by a discussion of emerging or future control options which may be applicable across several industrial surface coating categories.

a.   Wood Furniture Coating

The Wood furniture coating industry covers 10 SIC codes including: Wood Kitchen Cabinets; Wood Household Furniture (except upholstered); Wood Household Furniture (upholstered); Wood Television, Radios, Phonograph, and Sewing Machine Cabinets; Household Furniture Not Classified Elsewhere; Wood Office Furniture; Public Building and Related Furniture; Wood Office and Store Fixtures; Furniture and Fixtures Not Elsewhere Classified; and Custom Kitchen Cabinets. Area source emissions would typically account for the smaller facilities that are not covered in the point source inventory.

Under the 1990 CAAA, the wood furniture industry is covered by both a new control technique guideline (CTG) and a maximum achievable control technology (MACT) standard (EPA, 1996c). The MACT standard sets limits for hazardous air pollutant (HAP) content and establishes work practices and was originally promulgated in December of 1995. VOC reductions for the MACT standards are uncertain, as compliance with the HAP content standards only precludes the use of certain organics which are also HAPs. The work practice standards are

expected to result in reductions of VOC. The new CTG, published in 1996, applies to ozone nonattainment areas and the Ozone Transport Region (OTR). The overall level of reductions expected for compliance with presumptive reasonably available control technology (RACT) is 47 percent at an estimated cost of $967 per ton of VOC reduced. This will affect facilities emitting 25 tons per year or more, and therefore, will not affect the entire area source inventory. The overall reduction of 47 percent is applied to both the area and point source emitters since the breakdown of area source emissions by size category (above vs. below 25 tons per year [tpy]) is not known.

The CTG examined alternative controls that go beyond the presumptive RACT requirements. Hybrid waterborne systems can reduce emissions by 28 to 85 percent at a cost effectiveness ranging from a savings of $462 per ton to a cost of $11,500 per ton reduced. A full waterborne coating system (only technically feasible for plants with short finishing sequences) can result in reductions of 60 to 93 percent, with a cost effectiveness ranging from $1860 per ton to $8430 per ton. Add-on controls include thermal incinerators, catalytic incinerators, and a combination of carbon adsorbers and

Table II-4
Industrial Surface Coating Categories - CAA Baseline Controls

Pod	SCCs	CS	Source Category/CAA Control Measure	Percent Reduction (%)	Cost Per Ton ($/ton)	Notes	References
223	2401040000		Metal coil and can coating				
	2401045000	1	MACT	36	1,000	10-year MACT category. MACT has not yet been proposed.	Pechan, 1997a
224	2401015000		Wood product surface coating				
		1	MACT	30	446	10-year MACT category: wood building production (formerly flat wood paneling) and Plywood and composite wood products. MACT have not yet been proposed. MACT reductions based on wood furniture MACT.	Pechan, 1997a
225	2401020000		Wood furniture surface coating				
		1	MACT	30	446	MACT establishes HAP limits and sets work practices. VOC emission reductions are uncertain. Compliance 11/21/97.	Pechan-Avanti, 1998a & b
		2	New CTG	47	967	Applies to nonattainment area & OTR. Size cutoff is 25 tpy. Requirements include coating emission limits and work practices. Compliance by 5/20/98.	This report
240	2401030000		Paper surface coating				
		1	MACT	78	4,776	10-year MACT category. MACT has not yet been proposed.	Pechan, 1997a
245	2401025000		Metal furniture, appliances, misc. parts coating				
	2401060000 2401090000 2401050000	1	MACT	36	1,000	10-year MACT for appliances, metal furniture, and miscellaneous parts categories.	Pechan, 1997a
247	2401055000		Machinery, equipment, railroad coating				
	2401085000	1	MACT level of control	36	1,000	10-year MACT for metal parts and products. MACT has not yet been proposed.	Pechan, 1997a
250	2401075000		Aircraft surface coating (aerospace)				
		1	MACT/CTG	60	165	Options for compliance include work practice standards for cleaning operations, carbon adsorber use, no-HAP strippers, and control of HAP from spray coating and blast depainting operations. MACT promulgated 9/01/95. Initial compliance by	Pechan-Avanti, 1998a & b
251	2401080000		Marine surface coating (shipbuilding)				
		1	MACT	24	2,090	MACT promulgated 12/15/95 with initial compliance 12/16/97. Costs for model plants with less than 100 tpy are used for the area source category.	Pechan-Avanti, 1998a & b
253	2401065000		Electronic & other electrical				

Table II-4 (continued)

Pod	SCCs	CS	Source Category/CAA Control Measure	Percent Reduction (%)	Cost Per Ton ($/ton)	Notes	References
		1	MACT	36	5,000	10-year MACT for metal parts and products. MACT has not yet been proposed. MACT reduction based on a ROM analysis.	Pechan, 1997a
254	2401070000		Motor vehicle coating				
		1	MACT	36	1,000	10-year MACT category. MACT has not yet been proposed. Emission reductions based on a ROM analysis.	Pechan, 1997a

NOTE: All costs are in 1990 dollars.

SOURCES: Pechan, 1997a; Pechan-Avanti, 1998a; Pechan-Avanti, 1998b.

Table II-5
Industrial Surface Coating Categories - Additional Control Options

Pod	SCCs	CS	Source Category/CAA Control Measure	Percent Reduction (%)	Cost Per Ton ($/ton)	Notes	References
223	2401040000		Metal coil and can coating				
	2401045000	2	San Francisco Bay Area Rule 11	42	2,007	More stringent VOC content limits and limits for additional coatings.	This report
		3	Incineration	90	8,937	Based on the use of add-on controls such as incineration.	Pechan, 1997b
224	2401015000		Wood product surface coating				
		2	SCAQMD Rule 1104 Amended	53	881	The amended rule is expected to result in an incremental reduction of 17 percent, with only one facility (of two in the area) being out of compliance with the more stringent levels.	This report
		3	Incineration	86	40,202	High cost per ton is associated with the low VOC concentration streams. Cost is incremental to RACT-level low VOC content requirements	This report
225	2401020000		Wood furniture surface coating				
		3	Add-on Controls	75	20,000	Based on costs for small plants to install add-on control options.	This report
240	2401030000		Paper surface coating				
			No further controls identified				
245	2401025000		Metal furniture,appliances,misc. parts coating				
	2401060000 2401090000 2401050000	2	SCAQMD Rule 1107 Amended	55.2	2,027	Amended rule sets more stringent VOC content limits.	Pechan, 1997b
247	2401055000		Machinery, equipment, railroad coating				
	2401085000	2	SCAQMD Rule 1107 Amended	55.2	2,027	Amended rule sets more stringent VOC content limits.	Pechan, 1997b
250	2401075000		Aircraft surface coating (aerospace)				
			No further controls identified.				
251	2401080000		Marine surface coating (shipbuilding)				
		2	Incineration	90	8,937	Based on the use of add-on controls such as incineration.	Pechan, 1997b
253	2401065000		Electronic & other electrical				
		2	SCAQMD Rule 1164	70	5,976	Based on the use of add-on controls, the use of low-VOC coatings, and improved operating procedures.	Pechan, 1997b
254	2401070000		Motor vehicle coating				
		2	Incineration	90	8,937	Based on the use of add-on controls such as incineration.	Pechan, 1997b

Table II-5 (continued)

Pod	SCCs	CS	Source Category/CAA Control Measure	Percent Reduction (%)	Cost Per Ton ($/ton)	Notes	References

NOTE: All costs are in 1990 dollars.

SOURCE: Pechan, 1997b.

incinerators. Emission reductions range from 67 to 98 percent, and the cost effectiveness ranges from $468 per ton to more than $22,100 per ton. The highest costs for add-on controls are associated with the model plants with specialized casegoods and the smallest casegoods plant size.

Based on the above data, the control measures modeled for beyond CAAA requirements will be based on the use of add-on controls. Emission reductions of 75 percent will be modeled at a cost effectiveness of $20,000 per ton. Where facilities can achieve comparable reductions through the use of hybrid waterborne systems, full waterborne systems, or other alternative coatings (see the discussion on emerging controls at the end of the section on industrial coatings), reductions may be higher and costs may be lower than those estimated based on the add-on control measure. For some of the smallest facilities (i.e., smaller than those covered in the CTG), add-on controls may not be feasible.

b.   Wood Product Coating

This is a 10-year MACT source category, so CAA baseline controls are based on engineering judgement. This category is also covered by a CTG, although compliance with these RACT requirements should already be incorporated within the base year emission inventory for nonattainment areas. For other areas, it is assumed that the MACT requirements will bring all areas into compliance with any limits established in the CTG as well.

The SCAQMD recently considered an amendment to Rule 1104 (SCAQMD, 1999b), establishing more stringent limits for inks and exterior siding coatings for wood flat stock coatings. Rule 1104 already includes VOC content limits on interior wood paneling, specifications for application, and solvent cleaning requirements. There are only two facilities in the South Coast district which would be subject to the rule. One of these facilities already use coatings which comply with the lower limits. The amendments are expected to reduce emissions by 17 percent over current baseline levels at a cost-effectiveness of $1802 per ton of VOC reduced (1999 dollars). This results in an overall reduction of 53 percent at an incremental cost of $1429 per ton (1990 dollars) for an overall cost per ton of $762.

The SCAQMD identified thermal oxidation as an alternative control technique, with a destruction efficiency of at least 95 percent and a collection efficiency of at least 90 percent, for an overall reduction of 85.5 percent. For the one facility examined (which has coatings above the proposed limits), cost effectiveness is estimated at $40,202 per ton reduced (1999 dollars) for a reductions of 85.5 percent. The high cost effectiveness of add-on controls is due to the fact that low-VOC coatings have been already been adopted for many of the coating processes, lowering the baseline emissions from which reductions are measured.

The Bay Area and Placer County districts already have limits as stringent as those proposed by the SCAQMD. Therefore, it is difficult to determine whether other areas of the country, particularly ozone nonattainment areas, already have limits as stringent as those being considered by SCAQMD. This would require an examination of all State regulations to determine the VOC content limits of individual coatings for this industry. Since the California districts tend to be out front in efforts to reduce smog-forming air pollution, it will be assumed that other areas can achieve similar incremental reductions for this industry.

c.   Metal Coil and Can Coating

This is also a 10-year MACT source category and is also covered by a CTG which requires RACT in ozone nonattainment areas. It is assumed that the MACT standard will reduce emissions by 36 percent and that this will bring all areas into compliance with CTG requirements as well. Further reductions will then be examined incremental to RACT levels which set VOC content limits for various coating operations.

The San Francisco Bay Area has adopted more stringent VOC content limits for body spray coatings for both two and three piece cans; set VOC limits for end sealing compounds for non-food products; and set limits for interior and exterior body sprays used on drums, pails, and lids (BAAQMD, 1999). This amendment to Rule 11 is expected to further reduce emissions by 9 percent at a cost effectiveness of $8,400 per ton. The year of dollars is not

given in the control measure summary, so 1997 dollars is assumed since this was the year of adoption of the regulation. In 1990 dollars, this is $8,074 per ton. This brings the overall reduction to $2007 per ton at 42 percent reduction from uncontrolled emissions.

d. Emerging and Future Control Options for Industrial Surface Coating

Most recent regulatory efforts for achieving emission reductions from surface coating operations have relied on reformulation of the coatings and other materials used in the surface coating operations (e.g., surface preparation products). These have included waterborne, high solids, and low-VOC coatings. For some categories, waterborne and other reformulations may not be applicable because of performance. Other types of coatings include powder coatings and ultraviolet and electronic beam (UV/EB) coatings.

Biofiltration has been used in Europe, primarily for odor control. It has not gained widespread use in the United States due to the lower cost associated with add-on controls such as incineration and adsorption. Other treatment options for VOC streams include membrane separation, corona destruction, and photocatalytic destruction (EC/R, 1994).

Zeolite has received recent attention as a means to concentrate the VOC stream before the flow goes to the add-on control device, such as an incinerator (CATC, 1998; 1999). Since the cost of the add-on controls are directly related to the gas flowrate, concentrating the VOC stream will reduce the flow requirements for controlling VOC from low-VOC streams. This is particularly important for the surface coating industry since many sectors already use low-VOC coatings to comply with RACT and other regulations. Costs of $1,000 to $3,000 per ton have been reported for low-VOC concentration streams with the use of zeolite. Zeolite is also replacing carbon in adsorbers. This increases efficiency from 95 to 99 percent for low-VOC streams and also reduces the risk of carbon bed fires. Zeolite is currently being examined by CARB under their Innovative Clean Air Technologies program (CARB, 1999b) and has also been the focus of research by EPA's Clean Air Technology Center (CATC, 1998; 1999).

4. Aerosol Paints

The NAAQS analysis assumed a 60 percent reduction from aerosol paints for CARB's aerosol coating rule which was passed in 1995 (Pechan, 1997b). The rule called for a second tier of standards to take effect in 1999. In October of 1998, CARB proposed less stringent limits for certain products, stating that the original limits were not technologically and commercially feasible (CARB, 1998). For other products, the limits were unchanged, and for a few, the limits were made more stringent. The final limits are expected to result in a 42 percent reduction in aerosol coating emissions. The cost effectiveness is expected to range from less than $1.00 per pound to about $3.00 per pound of VOC reduced. The overall average cost effectiveness is estimated at $1.57 per pound (1988 dollars). Converting the 1990 dollars (using the PPI for aerosol paints), this is $2732 per ton of VOC reduced.

The cost analysis separates costs into fixed costs and recurring costs. Fixed costs account for research and development, which may include the purchase of an additional propellant tank. Recurring costs are the additional costs associated with the new propellant used to manufacture the complying product. Additional research is needed to develop fixed versus recurring cost estimates for this category.

5. Pesticides

Control strategies for pesticides include reformulation (with low VOC content), reducing fumigant usage, use of alternative and more effective application methods, microencapsulation, implementation of better integrated pest management programs, the use of alternative active ingredients, and reducing the use of crop oils (EPA, 1993).

Past modeling efforts have used the California Federal Implementation Plan (FIP) Rule as the basis for estimating emission reductions and costs for pesticide application. This calls for a 20 percent reduction in pesticide emissions. California intends to reach their goal by

switching to and/or encouraging the use of low-VOC pesticides and better Integrated Pest Management (IPM) practices.

CARB formed the Department of Pesticide Regulation (DPR) in 1991 to regulate all aspects of pesticide sales and use. The DPR has implemented a faster registration process so that new pesticide products can be more quickly integrated. The DPR also encourages better IPM practices by working with local agricultural agencies and rewarding those who demonstrate good practice or innovation.

No new regulations have been developed for pesticides as the DPR believes that the reduction goals will be met through reformulation (which is occurring without specific air regulations) and better IPM practices (CDPR, 1999). As such, no estimates of the cost for meeting the reduction goals has been estimated.

EPA's alternative control technique for pesticides was published in March of 1993 (EPA, 1993). While the document addresses cost, most of the information is cited as variable and unknown. Any costs that are given are registration costs or costs for new equipments. No cost per ton estimates, which can be applied in modeling, are available from the alternative control technique. The cost for the 20 percent reduction for the California FIP was estimated at $9,300 per ton. This cost is likely overestimated given the information available from California's DPR; however, no new cost effectiveness estimates are available to date. If other States regulate pesticides due to other environmental concern, then pesticide emissions may show a decrease without any cost incurred for air pollution regulation.

For modeling, the 20 percent reduction at $9,300 per ton will be retained until better information is available.

6. Degreasing

CARB indicates that South Coast Rules 1122 and 1171 represent the most effective strategy for reducing emissions from solvent cleaning and degreasing.

Rule 1122 applies to both batch and conveyorized degreasing. The latest amendments, from 1997, set lower VOC limits for batch loaded and conveyorized cold cleaners at 50 grams of VOC per liter of material. The amendments are estimated to reduce emissions from solvent degreasing tanks (as opposed to hand-held cleaning) by 76 percent by using widely available no- or low-VOC solvents. The expected cost is $1,391 per ton of VOC reduced (1997 dollars) (SCAQMD, 1997).

In the study to amend Rule 1122, the SCAQMD examined a more stringent option that would require airless batch cleaning systems or air-tight cleaning systems. This would reduce emissions by 98 percent. The incremental cost effectiveness of this option was estimated at $53,360 per ton (beyond the amended rule).

Rule 1171 applies to solvent cleaning operations that do not include placing the parts in a tank. The original rule was adopted in 1991 and amended in 1995. The last amendments were adopted in the fall of 1996. These amendments lower the VOC limit for repair and maintenance cleaning from 900 to 50 grams per liter and lowers the vapor pressure limit for the cleaning of printing press equipment and polyester resin application equipment. Emission reductions were estimated at 46 percent at a cost savings of ($1,066) to ($811) per ton of VOC reduced. In the study, the SCAQMD also evaluated a more stringent option that would reduce emissions by 61 percent. The incremental cost effectiveness of this option was estimated at $12,936 per ton. This option targets additional emission reductions from ink application equipment cleaning operations, reducing the compliance limit to 350 grams per liter (SCAQMD, 1996).

Since rules 1122 and 1171 are amendments to existing rules, it is possible that some areas may achieve reductions higher than those in the amendments. For the purposes of this study, it will be assumed that MACT and RACT will result in baseline levels equivalent to those from which the SCAQMD evaluated this control option.

Additional research is needed to determine the fixed versus recurring cost breakout for these regulations. In general, if new degreasing agents are used, little or no capital expenditures would be required. For the more stringent options, new equipment is required.

The 1996 NET inventory classifies degreasing emissions by industry as either open top and conveyorized or cold cleaning. The SCAQMD regulatin distinguishes by whether it is batch or hand-cleaning, with some requirements varying by industry for hand-cleaning. Since the cold cleaning SCCs do not cover the printing and resin industry, it will be assumed that both the open top/conveyorized and cold cleaning categories will be covered by Rule 1122 limits, resulting in a reduction of 76 percent at a cost of $1,249 per ton (1990 dollars). This will be applied incremental to any existing RACT control levels in the inventory.

A second measure, the requirement for airless batch cleaning systems or air-tight cleaning systems, will also be modeled at a 98 percent reduction and incremental cost of $47,919. The overall cost effectiveness for this measure is $9,789 per ton of VOC reduced.

## B.	POINT SOURCE CONTROL MEASURES

No additional control measures for point source VOC emitters have been developed at this time. The more stringent area source measures for industrial surface coating are candidates for point source control. In addition, the use of zeolite may make it more economical to control other point source emitters with low concentration VOC streams. Future effort on VOC point source emitters should also focus on better identifying sources with "99" SCCs (miscellaneous and other not classified).

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CHAPTER III
STATIONARY SOURCE NO$_x$

This chapter evaluates potential source control measures for point and area source NO$_x$ emitters. This chapter identifies the newly developed control measures, as well as revisions to measures developed in previous analyses. The general impetus for these revisions is the availability of new information.

Point source measures that control NO$_x$ are described first, followed by area source control measures for NO$_x$. Each subsection briefly describes the source category, available control techniques, and the control options selected for the analysis. The discussion of the control options selected for the analysis includes an evaluation of emission reductions and total annualized costs, and concludes with a listing of the references examined. Capital and O&M costs are discussed for those measures for which information was identified to estimate these costs.

A. POINT SOURCE NO$_x$ CONTROL MEASURES

Potential stationary source NO$_x$ control options were identified in a previous report for an analysis of EPA's NO$_x$ State Implementation Plan (SIP) Call (Pechan-Avanti, 1998). Table III-1 shows the percentage emission reduction and size-specific cost-effectiveness values (in annual 1990 dollars) for source category/control measure combinations. Boiler design capacity-based cost equations were created to provide costs for large industrial, commercial, and institutional (ICI) boilers and gas turbines. Table III-2 shows source category/control measure combinations and variables (in annual 1990 dollars) used for each to determine costs.

Several simplifying assumptions were made for this analysis. A discount rate of 7 percent and a capacity factor of 65 percent were assumed for all sources. The equipment life of each control was taken directly from the source category's respective Alternative Control Techniques (ACT) document.

The ACT documents listed available controls and costs for a variety of model plants, depending upon the source category. Model plants with emission levels of 1 ton per ozone season day and less were considered representative of "small" plants, while model plants with higher emissions were considered representative of "large" plants. From these determinations, default cost per ton values were then assigned for small and large sources, as shown in Table III-1. Each source category was also assigned a capital cost to annual cost ratio based upon information provided in the respective ACT document. In cases where the default cost per ton value was applied, a default capital and operating and maintenance cost could also be determined.

For large boilers and gas turbines, capacity-based information was available in the respective ACT document. In those cases, capacity-based equations were calculated using scaling factors for these source category/control measure combinations. The source

Table III-1
Unit Costs for NOₓ Control Technologies for Non-Utility Stationary Sources

Source Category/Control Measure			Percentage Emission Reduction	Average Cost per Ton	
				Small*	Large*
11	ICI Boilers - Coal/Wall				
	1	SNCR	40	1040	840
	3	LNB	50	1460	1090
	4	SCR	70	1260	1070
12	ICI Boilers - Coal/FBC				
	1	SNCR - Urea based	75	900	670
13	ICI Boilers - Coal/Stoker				
	1	SNCR	40	1015	817
14	ICI Boilers - Coal/Cyclone				
	1	SNCR	35	840	700
	2	Coal Reburn	50	1570	300
	3	SCR	80	820	700
	4	NGR	55	1570	300
15	ICI Boilers - Residual Oil				
	1	LNB	50	400	430
	2	LNB + FGR	60	1120	390
	3	SCR	80	1480	810
	4	SNCR	50	2580	1050
16	ICI Boilers - Distillate Oil				
	1	LNB	50	1180	2070
	2	LNB + FGR	60	2490	760
	3	SCR	80	2780	1510
	4	SNCR	50	4640	1890
17	ICI Boilers - Natural Gas				
	1	LNB	50	820	650
	2	LNB + FGR	60	2560	590
	3	OT + WI	65	680	320
	4	SCR	80	2230	1210
	5	SNCR	50	3870	1570
18	ICI Boilers - Wood/Bark/Stoker				
	1	SNCR - Urea based	55	1440	930
19	ICI Boilers - Wood/Bark/FBC				
	1	SNCR - NH₃ based	55	1320	960
20	ICI Boilers - MSW/Stoker				
	1	SNCR - Urea based	55	1690	1250
21	Internal Combustion Engines - Oil				
	1	IR	25	770	490
	4	SCR	80	2340	920
22	Internal Combustion Engines - Gas				
	1	IR	20	1020	550
	4	AF RATIO	20	1570	380
	7	AF + IR	30	1440	460
	10	L-E (Medium Speed)	87	380	0
	11	L-E (Low Speed)	87	1680	630
	12	SCR	90	2769	533
23	Gas Turbines - Oil				
	1	Water Injection	68	1290	650

Table III-1 (continued)

	Source Category/Control Measure	Percentage Emission Reduction	Average Cost per Ton	
			Small*	Large*
	2 SCR + Water Injection	90	2300	1010
24	Gas Turbines - Natural Gas			
	1 Water Injection	76	1510	730
	2 Steam Injection	80	1040	500
	3 LNB	84	490	100
	4 SCR + LNB	94	2570	600
	5 SCR + Steam Injection	95	2010	840
	6 SCR + Water Injection	95	2730	1130
25	Process Heaters - Distillate Oil			
	1 LNB	45	3470	970
	2 LNB + FGR	48	4250	1680
	3 SNCR	60	3180	1720
	4 ULNB	74	2140	610
	5 SCR	75	9230	6030
	6 LNB + SNCR	78	3620	1880
	7 LNB + SCR	92	9120	5250
26	Process Heaters - Residual Oil			
	1 LNB + FGR	34	3490	1380
	2 LNB	37	2520	710
	3 SNCR	60	1930	1100
	4 ULNB	73	1290	360
	5 LNB + SNCR	75	2300	1240
	6 SCR	75	5350	3590
	7 LNB + SCR	91	5420	3160
27	Process Heaters - Natural Gas			
	1 LNB	50	2200	1800
	2 LNB + FGR	55	3190	2470
	3 SNCR	60	2850	1950
	4 ULNB	75	1500	1200
	5 SCR	75	12040	8160
	6 LNB + SNCR	80	3520	2590
	7 LNB + SCR	88	11560	8020
28	Adipic Acid Manufacturing			
	1 Thermal Reduction	81	420	420
	2 Extended Absorption	86	90	90
29	Nitric Acid Manufacturing			
	1 Extended Absorption	95	480	480
	2 SCR	97	590	590
	3 SNCR	98	550	550
30	Glass Manufacturing - Container			
	1 Electric Boost	10	7150	7150
	2 Cullet Preheat	25	940	940
	3 LNB	40	1690	1690
	4 SNCR	40	1770	1770
	5 SCR	75	2200	2200
	6 OXY-Firing	85	4590	4590
31	Glass Manufacturing - Flat			
	1 Electric Boost	10	2320	2320

Table III-1 (continued)

Source Category/Control Measure			Percentage Emission Reduction	Average Cost per Ton	
				Small*	Large*
	2	LNB	40	700	700
	3	SNCR	40	740	740
	4	SCR	75	710	710
	5	OXY-Firing	85	1900	1900
32	Glass Manufacturing - Pressed				
	1	Electric Boost	10	8760	8760
	2	Cullet Preheat	25	810	810
	3	LNB	40	1500	1500
	4	SNCR	40	1640	1640
	5	SCR	75	2530	2530
	6	OXY-Firing	85	3900	3900
33	Cement Manufacturing - Dry				
	1	Mid-Kiln Firing	30	460	460
	2	LNB	25	560	560
	3	SNCR - Urea Based	50	770	770
	4	SNCR - NH_3 Based	50	850	850
	5	SCR	80	3370	3370
34	Cement Manufacturing - Wet				
	1	Mid-Kiln Firing	30	420	420
	2	LNB	25	530	530
	3	SCR	80	2880	2880
35	Iron & Steel Mills - Reheating				
	1	LEA	13	1320	1320
	2	LNB	66	300	300
	3	LNB + FGR	77	380	380
36	Iron & Steel Mills - Annealing				
	1	LNB	50	570	570
	2	LNB + FGR	60	750	750
	3	SNCR	60	1640	1640
	4	LNB + SNCR	80	1720	1720
	5	SCR	85	3830	3830
	6	LNB + SCR	90	4080	4080
37	Iron & Steel Mills - Galvanizing				
	1	LNB	50	490	490
	2	LNB + FGR	60	580	580
38	Municipal Waste Combustors				
	1	SNCR	45	1130	1130
39	Medical Waste Incinerators				
	1	SNCR	45	4510	4510
41	ICI Boilers - Process Gas				
	1	LNB	50	820	650
	2	LNB + FGR	60	2560	590
	3	OT + WI	65	680	320
	4	SCR	80	2230	1210
42	ICI Boilers - Coke				
	1	SNCR	40	1040	840
	3	LNB	50	1460	1090
	4	SCR	70	1260	1070

Table III-1 (continued)

Source Category/Control Measure			Percentage Emission Reduction	Average Cost per Ton	
				Small*	Large*
43	ICI Boilers - LPG				
	1	LNB	50	1180	2070
	2	LNB + FGR	60	2490	760
	3	SCR	80	2780	1510
	4	SNCR	50	4640	1890
44	ICI Boilers - Bagasse				
	1	SNCR - Urea based	55	1440	930
45	ICI Boilers - Liquid Waste				
	1	LNB	50	400	430
	2	LNB + FGR	60	1120	390
	3	SCR	80	1480	810
	4	SNCR	50	2580	1050
46	IC Engines - Gas, Diesel, LPG				
	1	IR	25	770	490
	4	SCR	80	2340	920
47	Process Heaters - Process Gas				
	1	LNB	50	2200	1800
	2	LNB + FGR	55	3190	2470
	3	SNCR	60	2850	1950
	4	ULNB	75	1500	1200
	5	SCR	75	12040	8160
	6	LNB + SNCR	80	3520	2590
	7	LNB + SCR	88	11560	8020
48	Process Heaters - LPG				
	1	LNB	45	3470	970
	2	LNB + FGR	48	4250	1680
	3	SNCR	60	3180	1720
	4	ULNB	74	2140	610
	5	SCR	75	9230	6030
	6	LNB + SNCR	78	3620	1880
	7	LNB + SCR	92	9120	5250
49	Process Heaters - Other Fuel				
	1	LNB + FGR	34	3490	1380
	2	LNB	37	2520	710
	3	SNCR	60	1930	1100
	4	ULNB	73	1290	360
	5	LNB + SNCR	75	2300	1240
	6	SCR	75	5350	3590
	7	LNB + SCR	91	5420	3160
50	Gas Turbines - Jet Fuel				
	1	Water Injection	68	1290	650
	2	SCR + Water Injection	90	2300	1010
54	Space Heaters - Distillate Oil				
	1	LNB	50	1180	2070
	2	LNB + FGR	60	2490	760
	3	SCR	80	2780	1510
	4	SNCR	50	4640	1890
55	Space Heaters - Natural Gas				

Table III-1 (continued)

Source Category/Control Measure			Percentage Emission Reduction	Average Cost per Ton	
				Small*	Large*
	1	LNB	50	820	650
	2	LNB + FGR	60	2560	590
	3	OT + WI	65	680	320
	4	SCR	80	2230	1210
	5	SNCR	50	3870	1570
56	Ammonia - NG-Fired Reformers				
	1	LNB	50	820	650
	2	LNB + FGR	60	2560	590
	3	OT + WI	65	680	320
	4	SCR	80	2230	1210
	5	SNCR	50	3870	1570
57	Ammonia - Oil-Fired Reformers				
	1	LNB	50	400	430
	2	LNB + FGR	60	1120	390
	3	SCR	80	1480	810
	4	SNCR	50	2580	1050
58	Lime Kilns				
	1	Mid-Kiln Firing	30	460	460
	2	LNB	30	560	560
	3	SNCR - Urea Based	50	770	770
	4	SNCR - NH$_3$ Based	50	850	850
	5	SCR	80	3370	3370
59	Comm./Inst. Incinerators				
	1	SNCR	45	1130	1130
60	Indust. Incinerators				
	1	SNCR	45	1130	1130
61	Sulfate Pulping - Recovery Furnaces				
	1	LNB	50	820	650
	2	LNB + FGR	60	2560	590
	3	OT + WI	65	680	320
	4	SCR	80	2230	1210
	5	SNCR	50	3870	1570
62	Ammonia Prod; Feedstock Desulfurization				
	2	LNB + FGR	60	2560	590
63	Plastics Prod-Specific; (ABS) Resin				
	2	LNB + FGR	55	3190	2470
64	Starch Mfg; Combined Operations				
	2	LNB + FGR	55	3190	2470
65	By-Product Coke Mfg; Oven Underfiring				
	3	SNCR	60	1640	1640
66	Pri Cop Smel; Reverb Smelt Furn				
	2	LNB + FGR	60	750	750
67	Iron Prod; Blast Furn; Blast Htg Stoves				
	3	LNB + FGR	77	380	380
68	Steel Prod; Soaking Pits				
	2	LNB + FGR	60	750	750
69	Fuel Fired Equip; Process Htrs; Pro Gas				
	2	LNB + FGR	55	3190	2470

Table III-1 (continued)

Source Category/Control Measure			Percentage Emission Reduction	Average Cost per Ton	
				Small*	Large*
70	Sec Alum Prod; Smelting Furn/Reverb				
	1	LNB	50	570	570
71	Steel Foundries; Heat Treating Furn				
	1	LNB	50	570	570
72	Fuel Fired Equip; Furnaces; Natural Gas				
	1	LNB	50	570	570
73	Asphaltic Conc; Rotary Dryer; Conv Plant				
	1	LNB	50	2200	1800
74	Ceramic Clay Mfg; Drying				
	1	LNB	50	2200	1800
75	Coal Cleaning-Thrml Dryer; Fluidized Bed				
	3	LNB	50	1460	1090
76	Fbrglass Mfg; Txtle-Type Fbr; Recup Furn				
	3	LNB	40	1690	1690
77	Sand/Gravel; Dryer				
	2	LNB + FGR	55	3190	2470
78	Fluid Cat Cracking Units; Cracking Unit				
	2	LNB + FGR	55	3190	2470
79	Conv Coating of Prod; Acid Cleaning Bath				
	1	LNB	50	2200	1800
80	Natural Gas Prod; Compressors				
	12	SCR	20	2769	533
81	In-Process; Bituminous Coal; Cement Kiln				
	3	SNCR - urea based	50	770	770
82	In-Process; Bituminous Coal; Lime Kiln				
	3	SNCR - urea based	50	770	770
83	In-Process Fuel Use; Bituminous Coal; Gen				
	1	SNCR	40	1260	940
84	In-Process Fuel Use; Residual Oil; Gen				
	2	LNB	37	2520	710
85	In-Process Fuel Use; Natural Gas; Gen				
	1	LNB	50	2200	1800
86	In-Proc; Process Gas; Coke Oven/Blast Furn				
	2	LNB + FGR	55	3190	2470
87	In-Process; Process Gas; Coke Oven Gas				
	1	LNB	50	2200	1800
88	Surf Coat Oper; Coating Oven Htr; Nat Gas				
	1	LNB	50	2200	1800
89	Solid Waste Disp; Gov; Other Incin; Sludge				
	1	SNCR	45	1130	1130

Table III-1 (continued)

Source Category/Control Measure	Percentage Emission Reduction	Average Cost per Ton	
		Small*	Large*
Key: IR			Ignition Timing Retard
LPG			Liquefied Petroleum Gas
LEA			Low Excess Air
LNB			Low-NO$_x$ Burner
LNB+FGR	Low-NO$_x$ Burner + Flue Gas Recirculation		
LNB+SCR	Low-NO$_x$ Burner + Selective Catalytic Reduction		
LNB+SNCR	Low-NO$_x$ Burner + Selective Noncatalytic Reduction		
OT+WI			Oxygen Trim + Water Injection
SCR			Selective Catalytic Reduction
SNCR			Selective Noncatalytic Reduction
ULNB			Ultra-Low NO$_x$ Burner

NOTES: *Small source cost per ton values are used to estimate control costs for all sources with 1996 NO$_x$ emissions below 1 tons per day (tpd). If the ozone season daily 1996 baseline NO$_x$ value is 1 ton or more, the cost per ton value for large sources is used.

Table III-2
Size-Specific Cost Equations for Large Sources

Source Category/Control Measure	Percentage Emission Reduction	Cost from No Control Baseline				Cost from RACT Baseline			
		Capital Multiplier	Exponent	Annual Multiplier	Exponent	Capital Multiplier	Exponent	Annual Multiplier	Exponent
11 ICI Boilers - Coal/Wall									
1 SNCR	40	110487.6	0.423	3440.9	0.7337	67093.8	0.423	7514.2	0.4195
3 LNB	50	53868.7	0.6	11861.1	0.6	53868.7	0.6	11861.1	0.6
4 SCR	70	82400.9	0.65	5555.6	0.7885	79002.2	0.65	8701.5	0.6493
12 ICI Boilers - Coal/FBC									
1 SNCR - Urea based	75	15972.8	0.6	4970.5	0.6	15972.8	0.6	3059.2	0.6
13 ICI Boilers - Coal/Stoker									
1 SNCR	40	110487.6	0.423	3440.9	0.7337	67093.8	0.423	7514.2	0.4195
15 ICI Boilers - Residual Oil									
4 SNCR	50	62148.8	0.423	2012.4	0.7229	48002.6	0.423	5244.4	0.4238
3 SCR	80	33206.3	0.65	2498.1	0.732	40891.3	0.65	4481.5	0.6501
16 ICI Boilers - Distillate Oil									
4 SNCR	50	62148.8	0.423	2012.4	0.723	48002.6	0.423	5244.4	0.4238
3 SCR	80	33206.3	0.65	2498.1	0.732	40891.3	0.65	4481.5	0.6501
17 ICI Boilers - Natural Gas									
5 SNCR	50	62148.8	0.423	2012.4	0.723	48002.6	0.423	5244.4	0.4238
4 SCR	80	33206.3	0.65	2498.1	0.732	40891.3	0.65	4481.5	0.6501
18 ICI Boilers - Wood/Bark/Stoker									
1 SNCR - Urea based	55	65820.1	0.3607	17777.1	0.3462	65820.1	0.361	17777.1	0.3462
19 ICI Boilers - Wood/Bark/FBC									
1 SNCR - NH$_3$ based	55	9855.6	0.6	4185.4	0.6	9855.6	0.6	4185.4	0.6
23 Gas Turbines - Oil									
1 Water Injection	68	54453.5	0.5686	9687.9	0.7597	54453.5	0.5686	9687.9	0.7597
2 SCR + Water Injection	90	123980.2	0.5925	36100.2	0.6564	70538.9	0.6059	28972.5	0.5764
24 Gas Turbines - Natural Gas									
1 Water Injection	76	4284.2	1.0142	145.7	1.468	4284.2	1.0142	145.7	1.468
2 Steam Injection	80	9693.1	0.9199	764.3	1.1472	9693.1	0.9199	764.3	1.1472
3 LNB	84	71281.1	0.505	7826.3	0.505	71281.1	0.505	7826.3	0.505
4 SCR + LNB	94	86461.8	0.6448	19916.7	0.6561	33203.7	0.7295	13920	0.6866
5 SCR + Steam Injection	95	90606.2	0.6695	25936.7	0.6903	15278.8	0.8512	5477.9	0.8365

Table III-2 (continued)

Source Category/Control Measure			Percentage Emission Reduction	Cost from No Control Baseline				Cost from RACT Baseline			
				Capital Multiplier	Exponent	Annual Multiplier	Exponent	Capital Multiplier	Exponent	Annual Multiplier	Exponent
	6	SCR + Water Injection	95	121119	0.5891	36298.9	0.6308	18026.5	0.8237	7607	0.7828

Key:
    LNB   Low-NO$_x$ Burner
    LNB+SCR   Low-NO$_x$ Burner + Selective Catalytic Reduction
    LNB+SNCR   Low-NO$_x$ Burner + Selective Noncatalytic Reduction
    SCR   Selective Catalytic Reduction
    SNCR   Selective Noncatalytic Reduction

NOTE: All costs in the form y=mx^b.

category ACT documents also contained enough information to determine the separate costs necessary for applying more stringent controls where RACT level controls already existed in the base year. In the case of incremental controls, it was assumed that the new, more stringent control levels modeled would be applied from uncontrolled emission levels.

Further detailed information on the calculation of these costs can be found in Pechan-Avanti's *Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis* (Pechan-Avanti, 1998).

B.   AREA SOURCE NO$_x$ CONTROL MEASURES

This section discusses area source control measures for NO$_x$. Each subsection describes the penetration rate, the fraction of emissions covered by each measure, assumed in the analysis.

Information on controls previously developed and used in this analysis can be found in Pechan-Avanti's *Additional Control Measure Evaluation for the Integrated Implementation of the Ozone and Particulate Matter National Ambient Air Quality Standards, and Regional Haze Program* (Pechan, 1997a).

1.   Agricultural Burning

Agricultural burning is defined as the intentional burning of agricultural fields for the purpose of waste reduction (Pechan, 1995).

a.   Description of Available Control Options

Emissions from agricultural burning may be reduced by limiting the types of material that can be burned, or based on ambient conditions, limiting the days on which materials can be burned. Because information was not available on the cost or emission reductions associated with limiting the types of materials that can be burned, this type of control is not modeled.

Since burning can simply be shifted to other acceptable periods, emission control costs are assumed to be zero for regulations that schedule the burning days where ozone exceedances are not predicted. Costs may be incurred if personnel scheduled to participate in the agricultural burning cannot be used elsewhere or if fire personnel or other professionals have been scheduled to participate. Assuming full compliance with the regulation, ozone season daily emission reductions from such a regulation would be 100 percent. However, annual emission reductions would not be expected, because there would likely be a shift in the timing of the emissions, not a reduction in the total amount of annual NO$_x$ emitted (as well as all other pollutants from agricultural burning). A compliance rate of 80 percent is used in estimating daily reductions. Annual emissions are not reduced (Pechan, 1997b).

b.   Control Options Selected for Analysis

A seasonal ban on agricultural burning is selected for analysis. Control efficiencies for ozone season daily emission reductions (there are no annual emission reductions) are presented in Table III-3.

2.   Commercial and Residential Water Heaters

Roughly one-quarter of all U.S. energy consumption is related to space heating, water heating, and air conditioning (SCAQMD, 1997). The following SCCs are subject to controls for water heating:

- 2103006000: Commercial and Institutional Natural Gas Water Heaters
- 2104006000: Residential Natural Gas Water Heaters

a.   Description of Available Control Options

The primary means of reducing emissions from natural gas-fired residential and commercial water heaters would be low-NO_x burners. Low-NOx burners are designed to control the combustion process with proper air/fuel mixing and increased heat dissipation to minimize thermal NO_x formation.

The heat pump water heater (HPWH) is another method for reducing NO_x emissions from this source. The HPWH uses the same vapor compression refrigeration technology as space conditioning heat pumps. Basically, the HPWH takes heat from the surrounding air and transfers it to the water in the storage tank. This reduces the amount needed to heat the water. The most common type of HPWH is the air to water variety. In addition, HPWH can provide supplemental cooling effect. Heat pump water heaters are best suited for applications with high, consistent, year-round water heating loads and a need for ventilation and/or space cooling and dehumidifying (SCAQMD, 1997). Examples include commercial laundries, restaurant kitchens, homes with large cooling loads, hot attics, etc.

Solar water heating could be another method in reducing NO_x emissions from this source. Non-concentrating solar collectors, such as flat-plate solar panels, are capable of providing sufficient domestic water heating capabilities. Conventional natural gas-fired water heaters (using low NO_x burners emitting 10 nanograms per joule of heat output, or less) would still continue to be used to supplement the solar component.

Other control technologies include the use of electric thermal storage systems for commercial or multiple housing units. For example, an insulated tank is filled with water to a predetermined level. The water to be used throughout the building is heated by passing through a heat exchanger located below the level of the insulated tank. This system can either be installed inside or outside a building, above or below ground level.

b. Control Options Selected for Analysis

Low-NO_x burners control costs have been updated for this analysis and, along with control efficiencies, are presented in Table III-3. Controls previously modeled, such as programs designed for buying new water heaters, can be found in previous Pechan-Avanti documents (Pechan, 1997a).

Table III-3
Revised Low-NO$_x$ Burner Control Measure for
Commercial and Residential Water Heaters

Year	Low-NO$_x$ Water Heater		Overall Control (%)	Cost Per Ton ($)
	Rule Penetration (%)	Control Efficiency (%)		
1996	0	75	0	595
2003	0	75	0	595
2006	40	75	30	595
2010	73	75	55	595

C.   REFERENCES

Pechan, 1995: The Pechan-Avanti Group, *Regional Particulate Strategies - Draft Report*, prepared for U.S. Environmental Protection Agency, Office of Policy Planning and Evaluation, Washington, DC, EPA Contract No. 68-D3-0035, Work Assignment No. I-54, September 29, 1995.

Pechan, 1997a: E.H. Pechan & Associates, Inc., *Additional Control Measure Evaluation for the Integrated Implementation of the Ozone and Particulate Matter National Ambient Air Quality Standards, and Regional Haze Program*, prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, EPA Contract Nos. 68-D3-0035, Work Assignment No. III-100, July 1997.

Pechan, 1997b: E.H. Pechan & Associates, Inc., *The Emission Reduction and Cost Analysis Model for NO$_x$ (ERCAM-NO$_x$) - Revised Documentation*, prepared for U.S. Environmental Protection Agency, Ozone Policy and Strategies Group, Research Triangle Park, NC, EPA Contract Nos. 68-D3-0035, Work Assignment No. III-93, September 1997.

Pechan, 1998: The Pechan-Avanti Group, *Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis*, prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Innovative Strategies and Economics Group, Research Triangle Park, NC, EPA Contract Nos. 68-D4-0102 (WA 4-12) and 68-D9-8052 (WA 0-3), September 17, 1998.

SCAQMD, 1997: South Coast Air Quality Management District, *1997 Air Quality Management Plan, Appendix IV-1: Stationary Source Control Measures*, November 1996.

CHAPTER IV
STATIONARY SOURCE SO$_2$

Control efficiencies and costs of systems used to control SO$_2$ emissions from point sources were based on the use of various flue gas desulfurization (FGD) scrubbing systems, sulfur recovery plants, and sulfuric acid plants. The use of FGD scrubbers for controlling SO$_2$ emissions has been applied to utility and industrial boilers for over 25 years and is now considered a mature technology which can be designed to control SO$_2$ emissions from most industrial sources. Switching to burning a lower-sulfur fuel is another method used to lower SO$_2$ emissions, but the economic feasibility of obtaining of a lower-sulfur fuel in sufficient quantities limits its application.

FGD scrubbers can be either wet or dry systems. In wet systems, a liquid sorbent is sprayed into the flue gas in an absorber vessel. Limestone and lime-based reagents are most frequently used in scrubbers in the United States. Dry and semi-dry FGD systems include spray dryers, and dry injection into a duct or a combustion zone.

Sulfur recovery and sulfuric acid plants are generally used to control the SO$_2$ in waste gas from processes involved in the nonferrous metal, elemental sulfur, and sulfuric acid production industries. Most of the ores from which nonferrous metals such as copper, zinc, and lead are extracted also contain sulfur which generally forms SO$_2$ upon removal from the ore, usually by heat. Sulfur recovery or sulfuric acid plants used to control emissions from elemental sulfur or sulfuric acid plants amount to improving the existing process to recover more salable material.

Control efficiency, capital costs, annual costs, and cost-effectiveness ranges for control technologies were based on information taken from various sources and estimated using professional judgement. Sources include journal articles, EPA documents, and reference materials. Cost data was not available for all control technologies. The dollar years of the cost data, control equipment lifetimes, and discount rates used to estimate annual costs are provided where available.

Section A details the control measure parameters used in ControlNET for the additional SO$_2$ measures. Section B of this chapter gives a description of the SO$_2$ source categories along with potential controls for each category. This includes control options for which modeling parameters (costs) were not available.

A.   COST ESTIMATES FOR RETROFIT CONTROL TECHNOLOGIES

Retrofit control options by source category are listed in Table IV-1. This table lists the source category, the applicable SO$_2$ technology, and the expected control efficiency (Pechan-Avanti, 1999).

FGD is a control option for most of the source categories that were evaluated. Costs for FGD scrubbers were developed using a computer spreadsheet model provided by EPA.

Table IV-1
Retrofit Control Options

SO₂ Group	Group Name	Control Strategy	Control Measure	Expected SO₂ Control Efficiency (%)
1	Sulfuric Acid Plants - Contact Absorber (99.9% Conversion)	1	FGD	90
2	Sulfuric Acid Plants - Contact Absorber (99% Conversion)	1	Dual absorption	90
2	Sulfuric Acid Plants - Contact Absorber (99% Conversion)	2	Dual absorption + FGD	99
3	Sulfuric Acid Plants - Contact Absorber (98% Conversion)	1	Dual absorption	95
3	Sulfuric Acid Plants - Contact Absorber (98% Conversion)	2	Dual absorption + FGD	99.5
4	Sulfuric Acid Plants - Contact Absorber (97% Conversion)	1	Dual absorption	96.7
4	Sulfuric Acid Plants - Contact Absorber (97% Conversion)	2	Dual absorption + FGD	99.67
5	Sulfuric Acid Plants - Contact Absorber (93% Conversion)	1	Dual absorption	98.6
5	Sulfuric Acid Plants - Contact Absorber (93% Conversion)	2	Dual absorption + FGD	99.86
6	Sulfur Recovery Plants - Elemental Sulfur (Claus: 2 Stage w/o control (92-95% removal))	1	Amine Scrubbing	98.4
6	Sulfur Recovery Plants - Elemental Sulfur (Claus: 2 Stage w/o control (92-95% removal))	2	Amine Scrubbing + FGD	99.84
7	Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage w/o control (95-96% removal))	1	Amine Scrubbing	97.8
7	Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage w/o control (95-96% removal))	2	Amine Scrubbing + FGD	99.78
8	Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage w/o control (96-97% removal))	1	Amine Scrubbing	97.1
8	Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage w/o control (96-97% removal))	2	Amine Scrubbing + FGD	99.71
9	Sulfur Recovery Plants - Sulfur Removal Process (99.9% removal)	1	FGD	90
10	Sulfur Recovery Plants - Elemental Sulfur Production (Not Classified)	1	FGD	90
11	Inorganic Chemical Manufacture	1	FGD	90
12a	By-Product Coke Manufacturing (Coke Oven Plants)	1	Vacuum Carbonate	82
12b	By-Product Coke Manufacturing (Other Processes)	1	FGD	90
13	Process Heaters (Oil and Gas Production Industry)	1	FGD	90
14	Primary Metals Industry	1	FGD	90
15	Secondary Metal Production	1	FGD	90
16	Mineral Products Industry	1	FGD	90
17	Pulp and Paper Industry (Sulfate Pulping)	1	FGD	90
18	Petroleum Industry	1	FGD	90
19	Bituminous/Subbituminous Coal (Industrial Boilers)	1	FGD	90
20	Residual Oil (Industrial Boilers)	1	FGD	90
21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)	1	FGD	90
22	In-process Fuel Use - Bituminous/Subbituminous Coal	1	FGD	90
23	Lignite (Industrial Boilers)	1	FGD	90
24	Residual Oil (Commercial/Institutional Boilers)	1	FGD	90
25	Municipal Waste Combustors	1	FGD	90

Table IV-1 (continued)

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SO$_2$ Group	Group Name	Control Strategy	Control Measure	Expected SO$_2$ Control Efficiency (%)
26	Steam Generating Unit-Coal/Oil	1	FGD	90
27	Primary Copper Smelters (copper converter, smelting furnace, and roaster)	1	Dual absorption	99
28	Primary Lead Smelters - Sintering	1	Dual absorption	99
29	Primary Zinc Smelters - Sintering	1	Dual absorption	99

The model is based on a wet FGD system and was developed from data presented in a report that analyzed the impacts of SO_2 controls on the electric power generation sector (EPA, 1996). To develop a method for estimating costs for emission sources in the 1990 emission inventory, the spreadsheet model was used to develop capital and operating cost components using the stack gas flow rate and stack gas temperature for emission points in the 1990 emission inventory as the independent variable (Pechan, 1997). Table IV-2 presents an illustration of the FGD spreadsheet model. The following describes the spreadsheet model and then describes the equations used to estimate costs for emission sources. Table IV-3 lists the SCCs for the various SO_2 groups.

All costs are expressed in 1990 dollars unless otherwise indicated. Capital costs were updated from these base years by means of the Chemical Engineering Cost Index. Operating costs were updated using the Producer Price Index.

1. FGD Scrubber Spreadsheet Cost Model

The key input parameters used as variables in the model include stack gas flow rate and temperature entering the scrubber, and annual operating time. The inputs for capital, fixed O&M, and variable O&M costs are used as constants in the model. These constants are based on data for FGD scrubber cost assumptions for utility boilers with a 3 percent coal sulfur content (EPA, 1996). The assumptions apply to capacities at or above 500 megawatts (MW) [approximately 1,000,000 actual cubic feet per minute (acfm)]. For smaller sizes, the costs are scaled down using the standard 0.6 power law. Thus, at lower capacities, capital costs [in dollars per kilowatt or $/acfm] are proportionately higher. In the spreadsheet model, costs are scaled down using the 0.6 power law if the gas flow rate is less than 1,028,000 acfm. A gas flow rate factor of 0.486 is used to convert costs from $/kilowatt to $/acfm. This factor was derived from data in the Integrated Air Pollution Control System (IAPCS) model (version 5). For existing emission sources, a retrofit factor of 1.1 is applied to the capital costs. A capital recovery factor of 0.1098 is used to estimate capital charges based on a 7-percent interest rate and a 15-year equipment life. The FGD scrubber cost assumptions are in 1995 dollars. Capital and annual costs are de-escalated to 1990 dollars using the ratio of Chemical Engineering Annual Plant Cost Indexes for 1990 and 1995.

2. Sulfuric Acid Plants

Technology for SO_2 emissions control from sulfuric acid plants is well established. The dual absorption process is operating successfully at many U.S. facilities. In addition, several desulfurization processes apply to tail gases from a sulfuric acid plant. Using a dual absorption process, a plant can convert 99.7 to 99.8 percent of the SO_2 produced to SO_3. The dual absorption process has proved to be the SO_2 control system of choice for the sulfuric acid industry since the promulgation of the New Source Performance Standards (NSPS).

Cost equations for dual absorption (EPA, 1985):

Capital cost = $990,000 + $9.836 * Flow rate (in cubic feet per minute [ft^3/minute])

Operating cost = $75,800 + $12.82 * Flow rate (in ft^3/minute)

Table IV-2
Illustration of FGD Scrubber Cost Spreadsheet Model

	Model Inputs	
-- Gas flow rate at FGD scrubber inlet [standard cubic feet per minute (scfm)] [1]	500,000	Variable
-- Gas temperature at FGD scrubber inlet (°F) [1]	400	Variable
-- SO_2 concentration at FGD scrubber inlet (vol. %)	1.0	Variable
-- Capital cost (1995 $/kilowatt) [2]	192	Constant
-- Fixed O&M cost (1995 $/kilowatt-year) [2]	6.9	Constant
-- Variable O&M cost (1995 $/kilowatt hour) [2]	0.0015	Constant
-- Flow Rate factor (kilowatt/acfm) [3]	0.486	Constant
-- FGD scrubber operating time (hour/year) [1]	8,736	Variable
-- FGD scrubber control efficiency (%) [2]	90	Constant
-- FGD scrubber useful life (year)	15	Constant
-- Interest (discount) rate (fraction)	0.07	Constant
-- Retrofit factor [2]	1.10	Constant
-- De-escalation factor [4]	0.9383	Constant

	Model Outputs
-- Gas flow rate at FGD inlet (acfm)	811,321
-- SO_2 inlet rate (tons/year)	124,063
-- Capital cost (1995 $/acfm) [5]	107.6
-- Fixed O&M cost (1995 $/acfm-year)	3.35
-- Variable O&M cost (1995 $/acfm-hour)	0.000729
-- Capital cost-retrofit (1995 $) [6]	96,028,000
-- Capital cost-retrofit (1990 $) [6]	90,103,000
-- Fixed O&M cost (1995 $/year) [6]	2,718,000
-- Variable O&M cost (1995 $/year) [6]	2,957,000
-- Capital recovery factor	0.1098
-- Capital recovery cost (1995 $/year) [6]	10,544,000
-- Total annual cost (1995 $/year) [6]	16,219,000
-- Total annual cost (1990 $/year) [6]	15,218,000
-- Cost effectiveness (1995 $/ton)	140
-- Cost effectiveness (1990 $/ton)	130

NOTES:

[1] Emission point-specific input value obtained from the National Particulates Inventory (NPI). Note that the gas flow rate in the NPI is reported in units of acfm. The NPI values were converted to scfm for the model.

[2] These costs are for the high sulfur (3 percent) case in the report. They apply to capacities at or above 500 MW (approximately 1,000,000 acfm). For smaller sizes, report suggests scaling down costs via the standard 0.6 power law. Thus, at lower capacities the capital cost (in $/kilowatt or $/acfm) will be higher (EPA, 1996).

[3] Factor derived from data in IAPCS model (version 5).

[4] Ratio of Chemical Engineering Plant Indexes (annual) for 1990 and 1995, respectively (357.6/381.1). Ratio used for both capital and annual costs.

[5] If flow rate < 1,028,000 acfm, cost is scaled down via 0.6 power law.

[6] Values are rounded to $1,000.

Table IV-3
SO$_2$ Groups and SCCs

SCC	SO$_2$ Group	Group Name
30102301	01	Sulfuric Acid Plants - Contact Absorber (99.9% Conversion)
30102306	02	Sulfuric Acid Plants - Contact Absorber (99% Conversion)
30102308	03	Sulfuric Acid Plants - Contact Absorber (98% Conversion)
30102310	04	Sulfuric Acid Plants - Contact Absorber (97% Conversion)
30102318	05	Sulfuric Acid Plants - Contact Absorber (93% Conversion)
30103201	06	Sulfur Recovery Plants - Elemental Sulfur (Claus: 2 Stage w/o control (92-95% removal))
30103202	07	Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage w/o control (95-96% removal))
30103203	08	Sulfur Recovery Plants - Elemental Sulfur (Claus: 3 Stage w/o control (96-97% removal))
30103204	09	Sulfur Recovery Plants - Sulfur Removal Process (99.9% removal)
30103299	10	Sulfur Recovery Plants - Elemental Sulfur Production (Not Classified)
30199999	11	Inorganic Chemical Manufacture
30100509	11	Inorganic Chemical Manufacture
30300315	12a	By-Product Coke Manufacturing (Coke Oven Plants)
30300401	12a	By-Product Coke Manufacturing (Coke Oven Plants)
30300302	12b	By-Product Coke Manufacturing (Other Processes)
30300303	12b	By-Product Coke Manufacturing (Other Processes)
30300304	12b	By-Product Coke Manufacturing (Other Processes)
30300306	12b	By-Product Coke Manufacturing (Other Processes)
30300308	12b	By-Product Coke Manufacturing (Other Processes)
30300313	12b	By-Product Coke Manufacturing (Other Processes)
30300314	12b	By-Product Coke Manufacturing (Other Processes)
31000402	13	Process Heaters (Oil and Gas Production Industry)
31000403	13	Process Heaters (Oil and Gas Production Industry)
31000404	13	Process Heaters (Oil and Gas Production Industry)
31000405	13	Process Heaters (Oil and Gas Production Industry)
31000412	13	Process Heaters (Oil and Gas Production Industry)
31000413	13	Process Heaters (Oil and Gas Production Industry)
30300101	14	Primary Metals Industry
30300102	14	Primary Metals Industry
30300105	14	Primary Metals Industry
30300103	14	Primary Metals Industry
30300199	14	Primary Metals Industry
30300201	14	Primary Metals Industry
30399999	14	Primary Metals Industry
30300813	14	Primary Metals Industry
30300817	14	Primary Metals Industry
30300824	14	Primary Metals Industry
30300825	14	Primary Metals Industry
30300901	14	Primary Metals Industry
30300908	14	Primary Metals Industry
30300911	14	Primary Metals Industry
30300931	14	Primary Metals Industry
30300933	14	Primary Metals Industry
30300999	14	Primary Metals Industry
30301001	14	Primary Metals Industry
30301002	14	Primary Metals Industry
30301101	14	Primary Metals Industry
30301199	14	Primary Metals Industry
30301201	14	Primary Metals Industry
30303003	14	Primary Metals Industry
30499999	15	Secondary Metal Production
30500606	16	Mineral Products Industry
30500612	16	Mineral Products Industry
30500622	16	Mineral Products Industry

Table IV-3 (continued)

SCC	SO$_2$ Group	Group Name
30500706	16	Mineral Products Industry
30500801	16	Mineral Products Industry
30501037	16	Mineral Products Industry
30501401	16	Mineral Products Industry
30501402	16	Mineral Products Industry
30501403	16	Mineral Products Industry
30501410	16	Mineral Products Industry
30501602	16	Mineral Products Industry
30501604	16	Mineral Products Industry
30501905	16	Mineral Products Industry
30502201	16	Mineral Products Industry
30502509	16	Mineral Products Industry
30599999	16	Mineral Products Industry
30501001	16	Mineral Products Industry
30501002	16	Mineral Products Industry
30501201	16	Mineral Products Industry
30501202	16	Mineral Products Industry
30501203	16	Mineral Products Industry
30501212	16	Mineral Products Industry
30501404	16	Mineral Products Industry
30501499	16	Mineral Products Industry
30700104	17	Pulp and Paper Industry (Sulfate Pulping)
30700106	17	Pulp and Paper Industry (Sulfate Pulping)
30700110	17	Pulp and Paper Industry (Sulfate Pulping)
30600101	18	Petroleum Industry
30600102	18	Petroleum Industry
30600103	18	Petroleum Industry
30600104	18	Petroleum Industry
30600105	18	Petroleum Industry
30600106	18	Petroleum Industry
30600199	18	Petroleum Industry
30600201	18	Petroleum Industry
30600202	18	Petroleum Industry
30600204	18	Petroleum Industry
30600301	18	Petroleum Industry
30600401	18	Petroleum Industry
30600402	18	Petroleum Industry
30600503	18	Petroleum Industry
30600504	18	Petroleum Industry
30600805	18	Petroleum Industry
30600902	18	Petroleum Industry
30600903	18	Petroleum Industry
30600904	18	Petroleum Industry
30600999	18	Petroleum Industry
30601001	18	Petroleum Industry
30601101	18	Petroleum Industry
30601201	18	Petroleum Industry
30601401	18	Petroleum Industry
30609903	18	Petroleum Industry
30609904	18	Petroleum Industry
30699998	18	Petroleum Industry
30699999	18	Petroleum Industry
10200201	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200202	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200203	19	Bituminous/Subbituminous Coal (Industrial Boilers)

Table IV-3 (continued)

SCC	SO$_2$ Group	Group Name
10200204	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200205	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200206	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200210	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200212	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200213	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200217	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200219	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200221	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200222	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200223	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200224	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200225	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200226	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200229	19	Bituminous/Subbituminous Coal (Industrial Boilers)
10200401	20	Residual Oil (Industrial Boilers)
10200402	20	Residual Oil (Industrial Boilers)
10200404	20	Residual Oil (Industrial Boilers)
10200405	20	Residual Oil (Industrial Boilers)
10300205	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300206	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300207	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300208	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300209	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300211	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300214	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300216	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300217	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300221	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300222	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300223	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300224	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300225	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
10300226	21	Bituminous/Subbituminous Coal (Commercial/Institutional Boilers)
39000288	22	In-process Fuel Use - Bituminous/Subbituminous Coal
39000289	22	In-process Fuel Use - Bituminous/Subbituminous Coal
39000299	22	In-process Fuel Use - Bituminous/Subbituminous Coal
10200301	23	Lignite (Industrial Boilers)
10200302	23	Lignite (Industrial Boilers)
10200303	23	Lignite (Industrial Boilers)
10200304	23	Lignite (Industrial Boilers)
10200306	23	Lignite (Industrial Boilers)
10200307	23	Lignite (Industrial Boilers)
10300401	24	Residual Oil (Commercial/Institutional Boilers)
10300402	24	Residual Oil (Commercial/Institutional Boilers)
10300404	24	Residual Oil (Commercial/Institutional Boilers)
50100101	25	Municipal Waste Combustors
50100102	25	Municipal Waste Combustors
50100103	25	Municipal Waste Combustors
50100104	25	Municipal Waste Combustors
50100105	25	Municipal Waste Combustors
10200101	26	Steam Generating Unit-Coal/Oil
10200104	26	Steam Generating Unit-Coal/Oil
10200107	26	Steam Generating Unit-Coal/Oil
10200501	26	Steam Generating Unit-Coal/Oil

Table IV-3 (continued)

SCC	SO$_2$ Group	Group Name
10200502	26	Steam Generating Unit-Coal/Oil
10200504	26	Steam Generating Unit-Coal/Oil
10200505	26	Steam Generating Unit-Coal/Oil
10201101	26	Steam Generating Unit-Coal/Oil
10201403	26	Steam Generating Unit-Coal/Oil
10201404	26	Steam Generating Unit-Coal/Oil
10299997	26	Steam Generating Unit-Coal/Oil
10300101	26	Steam Generating Unit-Coal/Oil
10300102	26	Steam Generating Unit-Coal/Oil
10300103	26	Steam Generating Unit-Coal/Oil
10300305	26	Steam Generating Unit-Coal/Oil
10300306	26	Steam Generating Unit-Coal/Oil
10300307	26	Steam Generating Unit-Coal/Oil
10300309	26	Steam Generating Unit-Coal/Oil
10300501	26	Steam Generating Unit-Coal/Oil
10300502	26	Steam Generating Unit-Coal/Oil
10300504	26	Steam Generating Unit-Coal/Oil
30300502	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300509	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300513	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300525	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300529	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300530	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300503	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300507	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300510	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300512	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300514	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300523	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300531	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300526	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300527	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300532	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300533	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300534	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300535	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300504	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300515	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300528	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30300521	27	Primary Copper Smelters (copper converter, smelting fumace, and roaster)
30301001	28	Primary Lead Smelters - Sintering
30303002	29	Primary Zinc Smelters - Sintering
30303007	29	Primary Zinc Smelters - Sintering
30303008	29	Primary Zinc Smelters - Sintering

3. Coke Ovens

The coke-oven gases produced by the controlled pyrolysis of coal contain reduced sulfur compounds, in addition to numerous hydrocarbons. About 25 to 30 percent of the sulfur in the coal is emitted in gaseous form as a constituent of the coke oven gas. Almost all of this sulfur is present as hydrogen sulfide (H_2S), with minor amounts of mercaptans. Using the coke oven gas to heat or underfire the coke ovens, or as fuel for other combustion operations, results in SO_2 emissions unless the H_2S is removed.

Several processes are suitable for removing H_2S from coke oven gases. In the vacuum carbonate process, H_2S is absorbed into a 3.0 to 3.5 percent solution of sodium carbonate. The H_2S is then stripped by steam from the absorbent in a reactivating tower. The reactivation is performed under vacuum to reduce the quantity of steam required. Conventional systems achieve about 90 percent removal.

Cost equations for vacuum carbonate (Emmel, et al., 1986):

Capital cost = $3,449,803 + $135.86 * Flow rate (ft^3/minute)

Operating cost = $797,667 + $58.54 * Flow rate (ft^3/minute)

4. Sulfur Recovery Plants

Refinery sour gas streams are generally fed to a regenerative type of H_2S removal process. The concentrated acid gas is then sent to the sulfur recovery unit. The Claus process is the most widely used method of producing sulfur from refinery H_2S. The modified Claus process is based on producing elemental sulfur by first converting one-third of the H_2S feed by precise combustion with air. The combustion products are then allowed to react thermally with the remaining two-thirds of the H_2S feed in the presence of a suitable catalyst to form sulfur vapor.

Cost equations for amine scrubbing:

Capital cost = $2,882,540 + $244.74 * Flow rate (ft^3/minute)

Operating cost = $749,170 + $148.40 * Flow rate (ft^3/minute)

B. SOURCE CATEGORY DESCRIPTIONS

1. Industrial Steam Generation – Bituminous/Subbituminous Coal

Gaseous sulfur oxide (SO_x) from coal combustion are primarily SO_2, with a much lower quantity of sulfur trioxide (SO_3) and gaseous sulfates. These compounds form as the organic and pyritic sulfur in the coal are oxidized during the combustion process. On average, about 95 percent of the sulfur present in bituminous coal will be emitted as gaseous SO_x, whereas somewhat less will be emitted when subbituminous coal is fired. The more alkaline nature of the ash in some subbituminous coals causes some of the sulfur to react in the furnace to form various sulfate salts that are retained in the boiler or in the flyash. Emissions from these sources are classified under SCC 102002xx (EPA, 1997).

a. Description of Available Control Options

Several techniques are used to reduce SO_2 emissions from coal combustion. One way is to switch to lower sulfur coals, since SO_2 emissions are proportional to the sulfur content of the coal. This alternative may not be possible where lower sulfur coal is not readily available or where a different grade of coal cannot be satisfactorily fired. In some cases, various coal cleaning processes may be employed to reduce the fuel sulfur content. Physical coal cleaning removes mineral sulfur such as pyrite but is not effective in removing organic sulfur. Chemical cleaning and solvent refining processes are being developed to remove organic sulfur (EPA, 1997).

Post-combustion FGD techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gases can be treated using wet, dry, or semi-dry desulfurization processes of either the throwaway type (in which all was streams are discarded) or the recovery/regenerable type (in which the SO_2 absorbent is regenerated and reused). To date, wet systems are the most commonly applied (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control and cost data for wet FGD scrubbing systems applied to industrial steam generation by combustion of bituminous/subbituminous coal were determined from EPA documents and recent technical literature. Wet FGD systems are a general category of control device in which, for SO_2 control, a liquid solution or liquid/solid slurry is used to absorb, and, in most cases, react with SO_2 in a waste gas stream. A scrubbing vessel, into which both the solution or slurry and the waste gas are introduced, is used to maximize the contact between the SO_2 in the waste gas and the reacting compounds in the solution or slurry (EPA, 1981).

The design of the scrubbing vessel and the manner in which the waste gas and the solution or slurry are introduced to the vessel are the means by which the reagent contact is controlled. Types of wet scrubber designs include: tray-type column, packed-bed column, mobile-bed column, venturi, and spray tower. Reagents used in wet scrubber systems include: calcium oxide (from lime), calcium carbonate (from limestone), magnesium oxide, sodium carbonate (soda ash), sodium hydroxide (caustic), sodium citrate, and ammonium hydroxide. Some wet scrubbing systems use a reagent which can be treated and reused and/or produces a saleable product, while other wet systems require that the spent reagent be treated and disposed of appropriately (EPA, 1981).

Wet FGD systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables. The lime and limestone wet scrubbing processes use a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible (EPA, 1997).

Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible (EPA, 1997).

Costs for FGD systems are often expressed in dollars per energy output in kilowatts. Capital costs for wet scrubbing systems generally fall within the range of $180 to $260 (1990 dollars) per kilowatt. Annualized cost effectiveness estimates in journal articles range from $340 to $630 (1990 dollars) per ton of SO_2 controlled. Annual costs were estimated using a 15-year equipment lifetime without the effects of inflation (Soud, et al., 1993, Smith, et al., 1994; Radcliffe, 1992; Torrens, 1990).

2.   Industrial Steam Generation – Lignite

The SO_x emissions from lignite combustion are a function of the sulfur content of the lignite and the lignite composition (i.e., sulfur content, heating value, and alkali concentration). The conversion of lignite sulfur to SO_x is generally inversely proportional to the concentration of alkali constituents in the lignite. The alkali content is known to have a great effect on sulfur conversion and acts as a built-in sorbent for SO_x removal. Emissions from these sources are classified under SCC 102003xx (EPA, 1997).

a.   Description of Available Control Options

FGD systems are in current operation on several lignite-fired utility boilers. Flue gases can be treated through wet, semi-dry, or dry desulfurization processes of either the throwaway type (in which all waste streams are discarded) or the recovery (regenerable) type (in which the SO_2 absorbent is regenerated and reused). To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove in excess of 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, spray drying, and dual alkali scrubbing are among the commercially proven FGD techniques (EPA, 1997).

Spray drying is a dry scrubbing approach in which a solution or slurry of alkaline material is sprayed into a reaction vessel as a fine mist and mixes with the flue gas. The SO_2 reacts with the alkali solution or slurry to form liquid-phase salts. The slurry is dried by the latent heat of the flue gas to about 1 percent free moisture. The dried alkali continues to react with SO_2 in the flue gas to form sulfite and sulfate salts. The spray dryer solids are entrained in the flue gas and carried out of the dryer to a particulate control device such as an electrostatic precipitator (ESP) or baghouse (EPA, 1997).

Limestone may also be injected into the furnace, typically in a fluidized bed combuster (FBC), to react with SO_2 and form calcium sulfate. An FBC is composed of a bed of inert material that is suspended or "fluidized" by a stream of air. Lignite is injected into this bed and burned. Limestone is also injected into this bed where it is calcined to lime and reacts with SO_2 to form calcium sulfate. Particulate matter emitted from the boiler is generally captured in a cyclone and recirculated or sent to disposal. Additional PM control equipment, such as an ESP or baghouse, is used after the cyclone to further reduce particulate emissions (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control and cost data for wet FGD scrubbing systems applied to industrial steam generation by combustion of lignite were determined from EPA documents and recent technical literature. Wet FGD systems are a general category of control device in which, for SO_2 control, a liquid solution or liquid/solid slurry is used to absorb, and, in most cases, react with SO_2 in a waste gas stream. A scrubbing vessel, into which both the solution or slurry and the waste gas are introduced, is used to maximize the contact between the SO_2 in the waste gas and the reacting compounds in the solution or slurry (EPA, 1981).

The design of the scrubbing vessel and the manner in which the waste gas and the solution or slurry are introduced to the vessel are the means by which the reagent contact is controlled. Types of wet scrubber designs include: tray-type column, packed-bed column, mobile-bed column, venturi, and spray tower. Reagents used in wet scrubber systems include: calcium oxide (from lime), calcium carbonate (from limestone), magnesium oxide, sodium carbonate (soda ash), sodium hydroxide (caustic), sodium citrate, and ammonium hydroxide. Some wet scrubbing systems use a reagent which can be treated and reused and/or produces a saleable product, while other wet systems require that the spent reagent be treated and disposed of appropriately (EPA, 1981).

Wet FGD systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables. The lime and limestone wet scrubbing processes use a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible (EPA, 1997).

Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible (EPA, 1997).

Costs for FGD systems are often expressed in dollars per energy output in kilowatts. Capital costs for wet scrubbing systems generally fall within the range of $180 to $260 (1990 dollars) per kilowatt. Annualized cost effectiveness estimates in journal articles range from $340 to $630 (1990 dollars) per ton of SO_2 controlled. Annual costs were estimated using a 15-year equipment lifetime without the effects of inflation (Soud, et al., 1993, Smith, et al., 1994; Radcliffe, 1992; Torrens, 1990).

3.   Industrial Steam Generation – Residual Oil

SO_x emissions are generated during oil combustion from the oxidation of sulfur contained in the fuel. The emissions of SO_x from conventional combustion systems are predominately in the form of SO_2. Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size, burner design, or grade of fuel being fired. On average, more than 95 percent of the fuel sulfur is converted to SO_2, about 1 to 5 percent is further oxidized to SO_3, and 1 to 3 percent is emitted as sulfate particulate. SO_3 readily reacts with water vapor (both in the atmosphere and in flue gases) to form a sulfuric acid mist. Emissions from these sources are classified under SCC 102004xx (EPA, 1997).

a.   Description of Available Control Options

Commercialized FGD processes use an alkaline reagent to absorb SO_2 in the flue gas and produce a sodium or a calcium sulfate compound. These solid sulfate compounds are then removed in downstream equipment. FGD technologies are categorized as wet, semi-dry, or dry depending on the state of the reagent as it leaves the absorber vessel. These processes are either regenerable (such that the reagent material can be treated and reused) or nonregenerable (in which case all waste streams are de-watered and discarded) (EPA, 1997).

Wet regenerable FGD processes are attractive because they have the potential for better than 95 percent sulfur removal efficiency, have minimal waste water discharges, and produce a saleable sulfur product. Some of the current nonregenerable calcium-based processes can, however, produce a saleable gypsum product (EPA, 1997).

To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems. Effectiveness of these devices depends not only on control device design but also on operating variables (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control and cost data for wet FGD scrubbing systems applied to industrial steam generation by combustion of residual oil were determined from EPA documents and recent technical literature. Wet FGD systems are a general category of control device in which, for SO_2 control, a liquid solution or liquid/solid slurry is used to absorb, and, in most cases, react with SO_2 in a waste gas stream. A scrubbing vessel, into which both the solution or slurry and the waste gas are introduced, is used to maximize the contact between the SO_2 in the waste gas and the reacting compounds in the solution or slurry (EPA, 1981).

The design of the scrubbing vessel and the manner in which the waste gas and the solution or slurry are introduced to the vessel are the means by which the reagent contact is controlled. Types of wet scrubber designs include: tray-type column, packed-bed column, mobile-bed column, venturi, and spray tower. Reagents used in wet scrubber systems include: calcium oxide (from lime), calcium carbonate (from limestone), magnesium oxide, sodium carbonate (soda ash), sodium hydroxide (caustic), sodium citrate, and ammonium hydroxide. Some wet scrubbing systems use a reagent which can be treated and reused and/or produces a saleable product, while other wet systems require that the spent reagent be treated and disposed of appropriately (EPA, 1981).

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Costs for FGD systems are often expressed in dollars per energy output in kilowatts. Capital costs for wet scrubbing systems generally fall within the range of $180 to $260 (1990 dollars) per kilowatt. Annualized cost effectiveness estimates in journal articles range from $340 to $630 (1990 dollars) per ton of SO_2 controlled. Annual costs were estimated using a 15-year equipment lifetime without the effects of inflation (Soud, et al., 1993, Smith, et al., 1994; Radcliffe, 1992; Torrens, 1990).

4.   Commercial/Institutional Steam Generation – Bituminous/Subbituminous Coal

Gaseous SO_x from coal combustion are primarily SO_2, with a much lower quantity of SO_3 and gaseous sulfates. These compounds form as the organic and pyritic sulfur in the coal are oxidized during the combustion process. On average, about 95 percent of the sulfur present in bituminous coal will be emitted as gaseous SO_x, whereas somewhat less will be emitted when subbituminous coal is fired. The more alkaline nature of the ash in some subbituminous coals causes some of the sulfur to react in the furnace to form various sulfate salts that are retained in the boiler or in the flyash. Emissions from these sources are classified under SCC 103002xx.

a.   Description of Available Control Options

Several techniques are used to reduce SO_2 emissions from coal combustion. One way is to switch to lower sulfur coals, since SO_2 emissions are proportional to the sulfur content of the coal. This alternative may not be possible where lower sulfur coal is not readily available or where a different grade of coal cannot be satisfactorily fired. In some cases, various coal cleaning processes may be employed to reduce the fuel sulfur content. Physical coal cleaning removes mineral sulfur such as pyrite but is not effective in removing organic sulfur. Chemical cleaning and solvent refining processes are being developed to remove organic sulfur (EPA, 1997).

Post-combustion FGD techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gases can be treated using wet, dry, or semi-dry desulfurization processes of either the throwaway type (in which all was streams are discarded) or the recovery/regenerable type (in which the SO_2 absorbent is regenerated and reused). To date, wet systems are the most commonly applied (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control and cost data for wet FGD scrubbing systems applied to commercial and institutional steam generation by combustion of bituminous/subbituminous coal were determined from EPA documents and recent technical literature. Wet FGD systems are a general category of control device in which, for SO_2 control, a liquid solution or liquid/solid slurry is used to absorb, and, in most cases, react with SO_2 in a waste gas stream. A scrubbing vessel, into which both the solution or slurry and the waste gas are introduced, is used to maximize the contact between the SO_2 in the waste gas and the reacting compounds in the solution or slurry (EPA, 1981).

The design of the scrubbing vessel and the manner in which the waste gas and the solution or slurry are introduced to the vessel are the means by which the reagent contact is controlled. Types of wet scrubber designs include: tray-type column, packed-bed column, mobile-bed column, venturi, and spray tower. Reagents used in wet scrubber systems include: calcium oxide (from lime), calcium carbonate (from limestone), magnesium oxide, sodium carbonate (soda ash), sodium hydroxide (caustic), sodium citrate, and ammonium hydroxide. Some wet scrubbing systems use a reagent which can be treated and reused and/or produces a saleable product, while other wet systems require that the spent reagent be treated and disposed of appropriately (EPA, 1981).

Wet FGD systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables. The lime and limestone wet scrubbing processes use a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible (EPA, 1997).

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Costs for FGD systems are often expressed in dollars per energy output in kilowatts. Capital costs for wet scrubbing systems generally fall within the range of $180 to $260 (1990 dollars) per kilowatt. Annualized cost effectiveness estimates in journal articles range from $340 to $630 (1990 dollars) per ton of SO_2 controlled. Annual costs were estimated using a 15-year equipment lifetime without the effects of inflation (Soud, et al., 1993, Smith, et al., 1994; Radcliffe, 1992; Torrens, 1990).

5.   Commercial/Institutional Steam Generation – Residual Oil

SO_x emissions are generated during oil combustion from the oxidation of sulfur contained in the fuel. The emissions of SO_x from conventional combustion systems are predominately in the form of SO_2. Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size, burner design, or grade of fuel being fired. On average, more than 95 percent of the fuel sulfur is converted to SO_2, about 1 to 5 percent is further oxidized to SO_3, and 1 to 3 percent is emitted as sulfate particulate. SO_3 readily reacts with water vapor (both in the atmosphere and in flue gases) to form a sulfuric acid mist. Emissions from these sources are classified under SCC 102004xx (EPA, 1997).

a.   Description of Available Control Options

Commercialized FGD processes use an alkaline reagent to absorb SO_2 in the flue gas and produce a sodium or a calcium sulfate compound. These solid sulfate compounds are then removed in downstream equipment. FGD technologies are categorized as wet, semi-dry, or dry depending on the state of the reagent as it leaves the absorber vessel. These processes are either regenerable (such that the reagent material can be treated and reused) or nonregenerable (in which case all waste streams are de-watered and discarded) (EPA, 1997).

Wet regenerable FGD processes are attractive because they have the potential for better than 95 percent sulfur removal efficiency, have minimal waste water discharges, and produce a saleable sulfur product. Some of the current nonregenerable calcium-based processes can, however, produce a saleable gypsum product (EPA, 1997).

To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems. Effectiveness of these devices depends not only on control device design but also on operating variables (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control and cost data for wet FGD scrubbing systems applied to commercial and institutional steam generation by combustion of residual oil were determined from EPA documents and recent technical literature. Wet FGD systems are a general category of control device in which, for SO_2 control, a liquid solution or liquid/solid slurry is used to absorb, and, in most cases, react with SO_2 in a waste gas stream. A scrubbing vessel, into which both the solution or slurry and the waste gas are introduced, is used to maximize the contact between the SO_2 in the waste gas and the reacting compounds in the solution or slurry (EPA, 1981).

The design of the scrubbing vessel and the manner in which the waste gas and the solution or slurry are introduced to the vessel are the means by which the reagent contact is controlled. Types of wet scrubber designs include: tray-type column, packed-bed column, mobile-bed column, venturi, and spray tower. Reagents used in wet scrubber systems include: calcium oxide (from lime), calcium carbonate (from limestone), magnesium oxide, sodium carbonate (soda ash), sodium hydroxide (caustic), sodium citrate, and ammonium hydroxide. Some wet scrubbing systems use a reagent which can be treated and reused and/or produces a saleable product, while other wet systems require that the spent reagent be treated and disposed of appropriately (EPA, 1981).

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Costs for FGD systems are often expressed in dollars per energy output in kilowatts. Capital costs for wet scrubbing systems generally fall within the range of $180 to $260 (1990 dollars) per kilowatt. Annualized cost effectiveness estimates in journal articles range from $340 to $630 (1990 dollars) per ton of SO_2 controlled. Annual costs were estimated using a 15-year equipment lifetime without the effects of inflation (Soud, et al., 1993, Smith, et al., 1994; Radcliffe, 1992; Torrens, 1990).

6.   Sulfuric Acid – Contact Process

The contact process for creating sulfuric acid is designed for use in plants where elemental sulfur is oxidized specifically in order to make acid. Nonferrous metals smelting plants, as well as some petroleum refineries, typically have high enough concentrations of SO_2 in waste gases to warrant construction of a sulfuric acid plant. Emissions from these sources are classified under SCC 301023xx (EPA, 1981; Friedman, 1981).

a.   Description of Available Control Options

Nearly all sulfur dioxide emissions from sulfuric acid plants are found in the exit stack gases. Extensive testing has shown that the mass of these SO_2 emissions is an inverse function of the sulfur conversion efficiency (SO_2 oxidized to SO_3). This conversion is always incomplete, and is affected by the number of stages in the catalytic converter, the amount of catalyst used, temperature and pressure, and the concentrations of the reactants (sulfur dioxide and oxygen). The double contact process has generally been accepted as the best available control technology for meeting NSPS emission limits. There are no byproducts or waste scrubbing materials created, only additional sulfuric acid. Wellman-Lord scrubbing is an alternative control technology for SO_2 emissions not controlled by a single- or double-contact sulfuric acid plant (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control and cost data for double-contact sulfuric acid plants and Wellman-Lord scrubbing systems applied to single contact sulfuric acid plants were determined from EPA documents and recent technical literature. The double-contact, or double-absorption, process for making sulfuric acid from waste gas containing SO_2 is essentially the same as the contact process with the addition of an interpass absorption tower. The waste gas is cleaned and dried as in the single-contact process before entering the process. Upon leaving the second or third catalyst bed, depending upon the process, the gas is cooled and introduced to a packed-bed, counter-current absorption tower where it contacts 98 to 99 percent sulfuric acid. After the absorbing tower, the gas is reheated and passed to the third or fourth catalyst bed, where approximately 97 percent of the remaining SO_2 is converted to SO_3 and passed to the final absorption tower for conversion to sulfuric acid as in the single-contact process. The typical control efficiency is from 98 to greater than 99 percent (EPA, 1981; EPA, 1997; Friedman, 1981.)

In the Wellman-Lord scrubbing process an aqueous sodium sulfite solution is used to absorb SO_2, usually in a counter-current tray-type column absorber. Sodium bisulfite is formed as the SO_2 is absorbed from the gas steam. The SO_2 is then released in a concentrated stream in the stripping step, in which sodium sulfite is recovered and returned to the absorber loop. The concentrated SO_x stream with water vapor enters a condenser, where most of the water is removed. If necessary, the resulting SO_2 stream may be further dried in a concentrated sulfuric acid drying tower. Sulfur compounds from the SO_x stream may be recovered as liquid SO_2, liquid SO_3, sulfuric acid, or elemental sulfur, as determined by potential use, market demand, and cost of transportation to the destination (EPA, 1997; EPA, 1981).

Before reaching the tray-tower absorber, particulates or fly ash are removed from the stream by an electrostatic precipitator, fabric filter, wet particulate scrubber, or other device. The stream is normally cooled to its adiabatic saturation temperature in a wet scrubber or presaturator. Humidification of the stream helps to reduce the evaporation of water in the absorbing scrubber. This step also serves to remove most of the chlorides in the stream, which can cause the scrubber water to become acidic, leading to stress corrosion. The typical control efficiency range is from 90 to 99 percent (EPA, 1997; EPA, 1981).

Capital costs for a double-contact acid plant ranges from $15 to 50 million (mid-1979 dollars) and operating costs range from $5 to $30 million (mid-1979 dollars) per year. Capital costs for a Wellman-Lord scrubbing system range from $500,000 to $2,500,000 (mid-1979 dollars), and operating costs range from $300,000 to $900,000 (mid-1979 dollars). The cost efficiency of Wellman-Lord scrubbing systems was estimated at $625 (1990 dollars) per ton of SO_2 controlled, based a 15-year equipment lifetime and not adjusted for inflation. Equipment lifetimes and discount rates for double contact acid plants were not found among the references (EPA, 1981; Radcliffe, 1992).

7.   Primary Copper Smelters – Copper Converter, Smelting Furnace, and Roaster

Roasters, smelting furnaces, and converters are sources of SO_x. In the standard Pierce-Smith copper converter, flue gases are captured during the blowing phase by the primary hood over the converter mouth. To prevent the hood from binding to the converter with splashing molten metal, a gap exists between the hood and the vessel. During charging and pouring

operations, significant fugitives may be emitted when the hood is removed to allow crane access. Remaining smelter operations process material containing very little sulfur, resulting in insignificant SO_2 emissions. Electrolytic refining does not produce emissions unless the associated sulfuric acid tanks are open to the atmosphere. Emissions from these sources are classified under SCC 303005xx (EPA, 1997).

a. Description of Available Control Options

Control of SO_2 from smelters is commonly performed by a sulfuric acid plant. Use of a sulfuric acid plant to treat copper smelter effluent gas streams requires that particulate-free gas containing minimum SO_2 concentrations, usually of at least three percent SO_2, be maintained. Sulfuric acid plants also treat converter gas effluent. Some multiple hearth and all fluidized bed roasters use sulfuric acid plants. Reverberatory furnace effluent contains minimal SO_2 and is usually released directly to the atmosphere with no SO_2 reduction. Effluent from the other types of smelter furnaces contain higher concentrations of SO_2 and are treated in sulfuric acid plants before being vented. Absorption of the SO_2 in dimethylaniline (DMA) solution has also been used in domestic smelters to produce liquid SO_2 (EPA, 1997).

b. Control Options Selected for Analysis

Emission control data for sulfuric acid plants and DMA scrubbing systems applied to primary copper smelters were determined from EPA documents and recent technical literature. The contact process is used to produce sulfuric acid from waste gas which contains SO_2. First, the waste gas must be pretreated, which usually involves dust removal, cooling, and scrubbing for further removal of particulate matter and heavy metals, mist, and moisture. After pretreatment, the gas is heated and passed through a catalytic converter (platinum mass units or units containing beds of pelletized vanadium pentoxide) to oxidize the SO_2 to SO_3. The exothermic, reversible oxidation reaction results in a conflict between high equilibrium conversions at lower temperatures and high reaction rates at high temperatures. Because of this, the gas is passed between the catalyst and two or three different heat exchangers in order to achieve conversion of SO_2 to SO_3 of about 92.5 to 98 percent. The gas leaving the final catalyst stage is cooled and introduced to an absorption tower by a stream of strong (98 to 99 percent) acid, where the SO_3 reacts with water in the acid to form additional sulfuric acid. Dilute sulfuric acid or water is added to the recirculating acid to maintain the desired concentration (EPA, 1981; EPA, 1997).

The double-contact, or double-absorption, process for making sulfuric acid from waste gas containing SO_2 is essentially the same as the single-contact process with the addition of an interpass absorption tower. The waste gas is cleaned and dried as in the single-contact process before entering the process. Upon leaving the second or third catalyst bed, depending upon the process, the gas is cooled and introduced to a packed-bed, counter-current absorption tower where it contacts 98 to 99 percent sulfuric acid. After the absorbing tower, the gas is reheated and passed to the third or fourth catalyst bed, where approximately 97 percent of the remaining SO_2 is converted to SO_3 and passed to the final absorption tower for conversion to sulfuric acid as in the single-contact process. No cost data were available for either single- or double-contact sulfuric acid plants controls (EPA, 1981; EPA, 1997).

The DMA absorption system is a cyclic-regenerative process that incorporates an absorber with trays on which most of the incoming SO_2 is absorbed in a countercurrent stream of DMA. The residual SO_2 in the gases is scrubbed with a weak sodium carbonate solution to give sodium sulfite or sodium bisulfite. Liquid sulfur dioxide is recovered as a product, and its absorbent is regenerated and recycled through the system. The typical control efficiency range is from 95 to 99 percent.

Capital costs for a double-contact acid plant ranges from $15 to 50 million (mid-1979 dollars) and operating costs range from $5 to $30 million (mid-1979 dollars) per year. Capital costs for DMA scrubbing systems are estimated to be $50 million (mid-1979 dollars), and annual operating costs are estimated at approximately $12 million (mid-1979 dollars). No cost efficiency estimate, equipment lifetime, or discount rate were available in the references for either control system (AWMA, 1992; EPA, 1981; Radcliffe, 1992).

8.   Primary Zinc Smelters – Sintering

The processing of zinc concentrate into metallurgical lead involves three major steps: sintering, reduction, and refining. The primary purpose of the sinter machine is the reduction of sulfur content of the feed material. Emissions from these sources are classified under SCC 30303003 (EPA, 1997).

a.   Description of Available Control Options

Control of SO_2 from smelters is commonly performed in a sulfuric acid plant. Use of a sulfuric acid plant to treat zinc smelter sinter effluent gas streams requires that particulate-free gas containing minimum SO_2 concentrations, usually of at least three percent SO_2, be maintained (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control data for sulfuric acid plants applied to primary zinc smelter sintering processes were determined from EPA documents and recent technical literature. The contact process is used to produce sulfuric acid from waste gas which contains SO_2. First, the waste gas must be pretreated, which usually involves dust removal, cooling, and scrubbing for further removal of particulate matter and heavy metals, mist, and moisture. After pretreatment, the gas is heated and passed through a catalytic converter (platinum mass units or units containing beds of pelletized vanadium pentoxide) to oxidize the SO_2 to SO_3. The exothermic, reversible oxidation reaction results in a conflict between high equilibrium conversions at lower temperatures and high reaction rates at high temperatures. Because of this, the gas is passed between the catalyst and two or three different heat exchangers in order to achieve conversion of SO_2 to SO_3 of about 92.5 to 98 percent. The gas leaving the final catalyst stage is cooled and introduced to an absorption tower by a stream of strong (98 to 99 percent) acid, where the SO_3 reacts with water in the acid to form additional sulfuric acid. Dilute sulfuric acid or water is added to the recirculating acid to maintain the desired concentration (EPA, 1981; EPA, 1997).

The double-contact, or double-absorption, process for making sulfuric acid from waste gas containing SO_2 is essentially the same as the single-contact process with the addition of an interpass absorption tower. The waste gas is cleaned and dried as in the single-contact process before entering the process. Upon leaving the second or third catalyst bed, depending upon the process, the gas is cooled and introduced to a packed-bed, counter-current absorption tower where it contacts 98 to 99 percent sulfuric acid. After the absorbing tower, the gas is reheated and passed to the third or fourth catalyst bed, where approximately 97 percent of the remaining SO_2 is converted to SO_3 and passed to the final absorption tower for conversion to sulfuric acid as in the single-contact process. No cost data were available for either single- or double-contact sulfuric acid plants controls (EPA, 1981; EPA, 1997).

Capital costs for a double-contact acid plant ranges from $15 to 50 million (mid-1979 dollars) and operating costs range from 5 to 30 million (mid-1979 dollars) per year. Cost efficiency estimates, equipment lifetimes, and discount rates for double-contact acid plants were not found among the references (EPA, 1981; Radcliffe, 1992).

9.   Primary Lead Smelters – Sintering

The processing of lead concentrate into metallurgical lead involves three major steps: sintering, reduction, and refining. The primary purpose of the sinter machine is the reduction of sulfur content of the feed material. This feed material typically consists of the following:

1. Lead concentrates, including pyrite concentrates that are high in sulfur content;

2. Lime rock and silica, incorporated in the feed to maintain a desired sulfur content;

3. High-lead-content sludge byproducts from other facilities; and

4. Undersized sinter recycled from the roast exiting the sinter machine.

Emissions from these sources are classified under SCC 30301029 (EPA, 1997).

a. Description of Available Control Options

Control of SO_2 from smelters is commonly performed by a sulfuric acid plant. Use of a sulfuric acid plant to treat lead smelter sinter effluent gas streams requires that particulate-free gas containing minimum SO_2 concentrations, usually of at least three percent SO_2, be maintained. Absorption of the SO_2 in DMA solution has also been used in domestic smelters to produce liquid SO_2 (EPA, 1997).

b. Control Options Selected for Analysis

Emission control data for sulfuric acid plants and DMA scrubbing systems applied to primary lead smelter sintering processes were determined from EPA documents and recent technical literature. The contact process is used to produce sulfuric acid from waste gas which contains SO_2. First, the waste gas must be pretreated, which usually involves dust removal, cooling, and scrubbing for further removal of particulate matter and heavy metals, mist, and moisture. After pretreatment, the gas is heated and passed through a catalytic converter (platinum mass units or units containing beds of pelletized vanadium pentoxide) to oxidize the SO_2 to SO_3. The exothermic, reversible oxidation reaction results in a conflict between high equilibrium conversions at lower temperatures and high reaction rates at high temperatures. Because of this, the gas is passed between the catalyst and two or three different heat exchangers in order to achieve conversion of SO_2 to SO_3 of about 92.5 to 98 percent. The gas leaving the final catalyst stage is cooled and introduced to an absorption tower by a stream of strong (98 to 99 percent) acid, where the SO_3 reacts with water in the acid to form additional sulfuric acid. Dilute sulfuric acid or water is added to the recirculating acid to maintain the desired concentration (EPA, 1981; EPA, 1997).

The double-contact, or double-absorption, process for making sulfuric acid from waste gas containing SO_2 is essentially the same as the single-contact process with the addition of an interpass absorption tower. The waste gas is cleaned and dried as in the single-contact process before entering the process. Upon leaving the second or third catalyst bed, depending upon the process, the gas is cooled and introduced to a packed-bed, counter-current absorption tower where it contacts 98 to 99 percent sulfuric acid. After the absorbing tower, the gas is reheated and passed to the third or fourth catalyst bed, where approximately 97 percent of the remaining SO_2 is converted to SO_3 and passed to the final absorption tower for conversion to sulfuric acid as in the single-contact process. No cost data was available for either single- or double-contact sulfuric acid plants controls (EPA, 1981; EPA, 1997).

The DMA absorption system is a cyclic-regenerative process that incorporates an absorber with trays on which most of the incoming SO_2 is absorbed in a countercurrent stream of DMA. The residual SO_2 in the gases is scrubbed with a weak sodium carbonate solution to give sodium sulfite or sodium bisulfite. Liquid sulfur dioxide is recovered as a product, and its absorbent is regenerated and recycled through the system. The typical control efficiency range is from 95 to 99 percent. Capital costs are estimated to be $50 million (mid-1979 dollars), and operating costs are estimated at approximately $12 million (mid-1979 dollars). No cost efficiency estimate, equipment lifetime, or discount rate were available in the references (AWMA, 1992; EPA, 1981).

10. Petroleum Refineries – Fluid Catalytic Cracking Units (FCCU)

Fluid catalytic cracking, using heat, pressure, and catalysts, converts heavy oils into lighter products with product distributions favoring the more valuable gasoline and distillate blending components. Feedstocks are usually gas oils from atmospheric distillation, vacuum distillation, coking, and deasphalting processes. These feedstocks typically have a boiling range of 340 to 540°C (650 to 1000°F). All of the catalytic cracking processes in use today can be classified as either fluidized-bed or moving-bed units (EPA, 1997).

The fluid catalytic cracking process uses a catalyst in the form of very fine particles that act as a fluid when aerated with a vapor. Fresh feed is preheated in a process heater and introduced into the bottom of a vertical transfer line or riser with hot regenerated catalyst. The hot catalyst vaporizes the feed, bringing both to the desired reaction temperature, 470 to 525°C (880 to 980°F). The high activity of modern catalysts causes most of the cracking reactions to take place in the riser as the catalyst and oil mixture flows upward into the reactor. The hydrocarbon vapors are separated from the catalyst particles by cyclones in the reactor. The reaction products are sent to a fractionator for separation (EPA, 1997).

The spent catalyst falls to the bottom of the reactor and is steam stripped as it exits the reactor bottom to remove absorbed hydrocarbons. The spent catalyst is then conveyed to a regenerator. In the regenerator, coke deposited on the catalyst as a result of the cracking reactions is burned off in a controlled combustion process with preheated air. Regenerator temperature is usually 590 to 675°C (1100 to 1250°F). The catalyst is then recycled to be mixed with fresh hydrocarbon feed. Emissions from these sources are classified under SCC 30600201 (EPA, 1997).

a.   Description of Available Control Options

Commercialized FGD processes use an alkaline reagent to absorb SO_2 in the flue gas and produce a sodium or a calcium sulfate compound. These solid sulfate compounds are then removed in downstream equipment. FGD technologies are categorized as wet, semi-dry, or dry depending on the state of the reagent as it leaves the absorber vessel. These processes are either regenerable (such that the reagent material can be treated and reused) or nonregenerable (in which case all waste streams are de-watered and discarded) (EPA, 1997).

Wet regenerable FGD processes are attractive because they have the potential for better than 95 percent sulfur removal efficiency, have minimal waste water discharges, and produce a saleable sulfur product. Some of the current nonregenerable calcium-based processes can, however, produce a saleable gypsum product (EPA, 1997).

To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems. Effectiveness of these devices depends not only on control device design but also on operating variables (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control and cost data for wet FGD scrubbing systems applied to FCCU at petroleum refineries were determined from EPA documents and recent technical literature. Wet FGD systems are a general category of control device in which, for SO_2 control, a liquid solution or liquid/solid slurry is used to absorb, and, in most cases, react with SO_2 in a waste gas stream. A scrubbing vessel, into which both the solution or slurry and the waste gas are introduced, is used to maximize the contact between the SO_2 in the waste gas and the reacting compounds in the solution or slurry (EPA, 1981).

The design of the scrubbing vessel and the manner in which the waste gas and the solution or slurry are introduced to the vessel are the means by which the reagent contact is controlled. Types of wet scrubber designs include: tray-type column, packed-bed column, mobile-bed column, venturi, and spray tower. Reagents used in wet scrubber systems include: calcium oxide (from lime), calcium carbonate (from limestone), magnesium oxide, sodium carbonate (soda ash), sodium hydroxide (caustic), sodium citrate, and ammonium hydroxide. Some wet scrubbing systems use a reagent which can be treated and reused and/or produces a saleable product, while other wet systems require that the spent reagent be treated and disposed of appropriately (EPA, 1981).

Wet FGD systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone

scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables. The lime and limestone wet scrubbing processes use a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible (EPA, 1997).

Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible (EPA, 1997).

Costs for FGD systems are often expressed in dollars per energy output in kilowatts. Capital costs for wet scrubbing systems generally fall within the range of $180 to $260 (1990 dollars) per kilowatt. Annualized cost effectiveness estimates in journal articles range from $340 to $630 (1990 dollars) per ton of SO_2 controlled. Annual costs were estimated using a 15-year equipment lifetime without the effects of inflation (Soud, et al., 1993, Smith, et al., 1994; Radcliffe, 1992; Torrens, 1990).

11.   Petroleum Refineries – Claus Sulfur Recovery

Sulfur recovery plants are used in petroleum refineries to convert the H_2S separated from refinery gas streams into the more disposable, and sometimes saleable, byproduct, elemental sulfur. Most plants are now built with two catalytic stages, although some air quality jurisdictions require three. From the condenser of the final catalytic stage, the process stream passes to some form of tailgas treatment process. The tailgas, containing H_2S, SO_2, sulfur vapor, and traces of other sulfur compounds formed in the combustion section, escapes with the inert gases from the tail end of the plant. Thus, it is frequently necessary to follow the Claus unit with a tailgas cleanup unit to achieve higher recovery. Emissions from these sources are classified under SCC 30603301 (EPA, 1997).

a.   Description of Available Control Options

Emissions from the Claus process may be reduced by: (1) extending the Claus reaction into a lower temperature liquid phase; (2) adding a scrubbing process to the Claus exhaust stream; or (3) incinerating the hydrogen sulfide gases to form sulfur dioxide. Currently, there are five processes available that extend the Claus reaction into a lower temperature liquid phase including the BSR/selectox, Sulfreen, Cold Bed Absorption, Maxisulf, and IFP-1 processes. These processes take advantage of the enhanced Claus conversion at cooler temperatures in the catalytic stages. All of these processes give higher overall sulfur recoveries of 98 to 99 percent when following downstream of a typical two- or three-stage Claus sulfur recovery unit, and therefore reduce sulfur emissions (EPA, 1997).

Sulfur emissions can also be reduced by adding a scrubber at the tail end of the plant. There are essentially two generic types of tailgas scrubbing processes: oxidation tailgas scrubbers and reduction tailgas scrubbers. The first scrubbing process is used to scrub SO_2 from incinerated tailgas and recycle the concentrated SO_2 stream back to the Claus process for conversion to elemental sulfur. There are at least three oxidation scrubbing processes: the sodium sulfite (Wellman-Lord), Stauffer Aquaclaus, and IFP-2. Only the sodium scrubbing process has been applied successfully to U.S. refineries (EPA, 1997).

In the second type of scrubbing process, sulfur in the tailgas is converted to H_2S by hydrogenation in a reduction step. After hydrogenation, the tailgas is cooled and water is removed. The cooled tailgas is then sent to the scrubber for H_2S removal prior to venting. There are at least four reduction scrubbing processes developed for tailgas sulfur removal: Beavon, Beavon MDEA, SCOT, and ARCO. In the Beavon process, H_2S is converted to sulfur outside the Claus unit using a

lean H$_2$S-to-sulfur process (the Strefford process). The other three processes utilize conventional amine scrubbing and regeneration to remove H$_2$S and recycle back as Claus feed (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control and cost data for sodium FGD scrubbing systems applied to Claus process sulfur plants at petroleum refineries were determined from EPA documents and recent technical literature. In the Wellman-Lord scrubbing process an aqueous sodium sulfite solution is used to absorb SO$_2$, usually in a counter-current tray-type column absorber. Sodium bisulfite is formed as the SO$_2$ is absorbed from the gas steam. The SO$_2$ is then released in a concentrated stream in the stripping step, in which sodium sulfite is recovered and returned to the absorber loop. The concentrated SO$_x$ stream with water vapor enters a condenser, where most of the water is removed. If necessary, the resulting SO$_2$ stream may be further dried in a concentrated sulfuric acid drying tower. Sulfur compounds from the SO$_x$ stream may be recovered as liquid SO$_2$, liquid SO$_3$, sulfuric acid, or elemental sulfur, as determined by potential use, market demand, and cost of transportation to the destination (EPA, 1997; EPA, 1981).

Before reaching the tray-tower absorber, particulates or fly ash are removed from the stream by an electrostatic precipitator, fabric filter, wet particulate scrubber, or other device. The stream is normally cooled to its adiabatic saturation temperature in a wet scrubber or presaturator. Humidification of the stream helps to reduce the evaporation of water in the absorbing scrubber. This step also serves to remove most of the chlorides in the stream, which can cause the scrubber water to become acidic, leading to stress corrosion. The typical control efficiency range is from 90 to 99 percent (EPA, 1997; EPA, 1981).

Capital costs for a Wellman-Lord scrubbing system ranges from $500,000 to $2,500,000 (mid-1979 dollars), and operating costs range from $300,000 to $900,000 (mid-1979 dollars). The cost efficiency of Wellman-Lord scrubbing systems was estimated at $625 (1990 dollars) per ton of SO$_2$ controlled, based a 15-year equipment lifetime and not adjusted for inflation (EPA, 1981; Radcliffe, 1992).

12.   Natural Gas Processing

Natural gas from high-pressure wells is usually passed through field separators at the well to remove hydrocarbon condensate and water. Natural gasoline, butane, and propane are usually present in the gas, and gas processing plants are required for the recovery of these liquefiable constituents. Natural gas is considered "sour" if H$_2$S is present in amounts greater than 5.7 milligrams per normal cubic meters (mg/nm^3) (0.25 grains per 100 standard cubic feet [gr/100 scf]). The H$_2$S must be removed (called "sweetening" the gas) before the gas can be utilized. Many chemical processes are available for sweetening natural gas. At present, the amine process (also known as the Girdler process), is the most widely used method for H$_2$S removal. Emissions from these sources are classified under SCC 310002xx (EPA, 1997).

a.   Description of Available Control Options

The H$_2$S gas removed through processing natural gas may be: (1) vented; (2) flared in waste gas flares or modern smokeless flares; (3) incinerated; or (4) utilized for the production of elemental sulfur or sulfuric acid (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control and cost data for elemental sulfur production using the Claus process applied to natural gas processing were determined from EPA documents and recent technical literature. The Claus process involves burning one-third of the available H$_2$S with air in a reactor furnace to form SO$_2$. The furnace normally operates at combustion chamber temperatures ranging from 980 to 1540°C (1800 to 2800°F) with pressures rarely higher than 70 kilopascals (kPa) (10 pounds per square inch absolute). Before entering a sulfur condenser, hot gas from the combustion chamber is quenched in a waste heat boiler that generates high to medium pressure steam. About 80 percent of the heat released could be recovered as useful energy. Liquid sulfur

from the condenser runs through a seal leg into a covered pit from which it is pumped to trucks or railcars for shipment to end users. Approximately 65 to 70 percent of the sulfur is recovered. The cooled gases exiting the condenser are then sent to the catalyst beds (EPA, 1997; EPA, 1981).

The remaining uncombusted two-thirds of the hydrogen sulfide undergoes Claus reaction (reacts with SO_2) to form elemental sulfur. The catalytic reactors operate at lower temperatures, ranging from 200 to 315°C (400 to 600°F). Alumina or bauxite is sometimes used as a catalyst. Because this reaction represents an equilibrium chemical reaction, it is not possible for a Claus plant to convert all the incoming sulfur compounds to elemental sulfur. Therefore, two or more stages are used in series to recover the sulfur. Each catalytic stage can recover half to two-thirds of the incoming sulfur. The number of catalytic stages depends upon the level of conversion desired (EPA, 1997; EPA, 1981).

The typical control efficiency range for a Claus process sulfur plant is from 95 to 99 percent. A two-stage catalytic Claus plant can achieve 94 to 96 percent efficiency, while a three-stage ranges from 96 to 97.5 percent, and a four-stage from 97 to 98.5 percent. The addition of a low-temperature stage after the final normal-temperature stage can extend control efficiencies to the 98 to 99 percent range (EPA, 1997; EPA, 1981).

Capital costs for a Claus sulfur plant ranges from $1 to 4 million (mid-1979 dollars) and operating costs range from $100,000 to $400,000 (mid-1979 dollars) per year. Operating costs are also estimated to be between $119 and $124 (1981 dollars) per ton of sulfur produced. Cost efficiency estimates, equipment lifetimes, and discount rates for double contact acid plants were not found among the references (EPA, 1981; Friedman, 1981).

13.   In-process Fuel Use – Bituminous/Subbituminous Coal

Coal is commonly used as a fuel to fire kilns in the manufacture of both cement and lime. SO_2 may be generated both from the sulfur compounds in the raw materials and from sulfur in the fuel. The sulfur content of both raw materials and fuels varies from plant to plant and with geographic location. However, the alkaline nature of the cement and the presence of calcium oxides from lime provides for direct absorption of SO_2, thereby mitigating the quantity of SO_2 emissions in the exhaust stream. Depending on the process and the source of the sulfur, SO_2 absorption ranges from about 70 percent to more than 95 percent. Emissions from these sources are classified under SCC 390002xx (EPA, 1997).

a.   Description of Available Control Options

Commercialized FGD processes use an alkaline reagent to absorb SO_2 in the flue gas and produce a sodium or a calcium sulfate compound. These solid sulfate compounds are then removed in downstream equipment. FGD technologies are categorized as wet, semi-dry, or dry depending on the state of the reagent as it leaves the absorber vessel. These processes are either regenerable (such that the reagent material can be treated and reused) or nonregenerable (in which case all waste streams are de-watered and discarded) (EPA, 1997).

Wet regenerable FGD processes are attractive because they have the potential for better than 95 percent sulfur removal efficiency, have minimal waste water discharges, and produce a saleable sulfur product. Some of the current nonregenerable calcium-based processes can, however, produce a saleable gypsum product (EPA, 1997).

To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems. Effectiveness of these devices depends not only on control device design but also on operating variables (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control and cost data for wet FGD scrubbing systems applied to FCCU at petroleum refineries were determined from EPA documents and recent technical literature. Wet FGD systems are a general category of control device in which, for SO_2 control, a liquid solution or liquid/solid slurry is used to absorb, and, in most cases, react with SO_2 in a waste gas stream. A scrubbing vessel, into which both the solution or slurry and the waste gas are introduced, is used to maximize the contact between the SO_2 in the waste gas and the reacting compounds in the solution or slurry (EPA, 1981).

The design of the scrubbing vessel and the manner in which the waste gas and the solution or slurry are introduced to the vessel are the means by which the reagent contact is controlled. Types of wet scrubber designs include: tray-type column, packed-bed column, mobile-bed column, venturi, and spray tower. Reagents used in wet scrubber systems include: calcium oxide (from lime), calcium carbonate (from limestone), magnesium oxide, sodium carbonate (soda ash), sodium hydroxide (caustic), sodium citrate, and ammonium hydroxide. Some wet scrubbing systems use a reagent which can be treated and reused and/or produces a saleable product, while other wet systems require that the spent reagent be treated and disposed of appropriately (EPA, 1981).

Wet FGD systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables. The lime and limestone wet scrubbing processes use a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible (EPA, 1997).

Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible (EPA, 1997).

Costs for FGD systems are often expressed in dollars per energy output in kilowatts. Capital costs for wet scrubbing systems generally fall within the range of $180 to $260 (1990 dollars) per kilowatt. Annualized cost effectiveness estimates in journal articles range from $340 to $630 (1990 dollars) per ton of SO_2 controlled. Annual costs were estimated using a 15-year equipment lifetime without the effects of inflation (Soud, et al., 1993, Smith, et al., 1994; Radcliffe, 1992; Torrens, 1990).

14.   Municipal Waste Combustors (MWC)

The chief acid gases of concern from the combustion of municipal solid waste are HCl and SO_2. Hydrogen fluoride (HF), hydrogen bromide (HBr), and SO_3 are also generally present, but at much lower concentrations. Concentrations of HCl and SO_2 in MWC flue gases directly relate to the chlorine and sulfur content in the waste. The chlorine and sulfur content vary considerably based on seasonal and local waste variations. Emissions of SO_2 from MWCs depend on the chemical form of sulfur in the waste, the availability of alkali materials in combustion-generated fly ash that act as sorbents, and the type of emission control system used. SO_2 concentrations are considered to be independent of combustion conditions. Sulfur is contained in many constituents of MSW, such as asphalt shingles, gypsum wallboard, and tires. Emissions from these sources are classified under SCC 501001xx (EPA, 1997).

a.   Description of Available Control Options

Commercialized FGD processes use an alkaline reagent to absorb SO_2 in the flue gas and produce a sodium or a calcium sulfate compound. These solid sulfate compounds are then removed in downstream equipment. FGD technologies are categorized as wet, semi-dry, or

dry depending on the state of the reagent as it leaves the absorber vessel. These processes are either regenerable (such that the reagent material can be treated and reused) or nonregenerable (in which case all waste streams are de-watered and discarded) (EPA, 1997).

To date, spray dryers are most the common FGD systems applied to MWC in the United States. Both spray dryers and dry sorbent injection systems are generally used with fabric filters to remove spent sorbent as well as for control of other pollutants, such as particulate matter and toxics. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems, though they are most often used to control MWC emissions in Japan and Europe. Effectiveness of these devices depends not only on control device design but also on operating variables (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control and cost data for spray dryers, dry sorbent injection, and wet scrubbing FGD systems applied to MWC were determined from EPA documents and recent technical literature. In a spray-dryer system, waste gas at air preheater temperatures (generally, 275°F to 400°F) is contacted with a solution or slurry of alkaline material, generally lime or sodium carbonate, in a vessel for five to fifteen seconds residence time. The hot gas is adiabatically humidified to within 50°F of its saturation temperature by the water evaporated from the solution or slurry. As the slurry or solution is evaporated, liquid phase salts are precipitated and the remaining solids are dried to generally less than one percent free moisture. These solids, along with any ash in the waste stream, are entrained by the waste gas to a particulate collection device, either an ESP or a fabric filter (baghouse). Reaction between the alkaline material and waste gas SO_2 proceeds both during and following the drying process. The by-product is a dry mixture of sulfite, sulfate, fly ash, and unreacted reagent. Generally, part of the by-product is recycled and mixed with fresh reagent to enhance sorbent utilization (EPA, 1997; Smith, et al., 1994; EPA, 1981).

The typical control efficiency range for spray dryer systems is from 30 to 90 percent. Systems which operate in the higher efficiency range are those which treat waste gas streams with a high enough concentration of SO_2 to efficiently utilize reagent and recycle reagent for maximum reagent usage (Smith, et al., 1994; Dennis, et al., 1993).

The dry sorbent injection process generally involves pneumatically introducing a dry, powdery alkaline material, generally calcium-based (lime or limestone), although sodium-based (nahcolite or trona) sorbents are also used, into a waste gas stream with subsequent particulate collection. The injection point has been varied from the boiler furnace exit to the entrance to an ESP or, more typically, a baghouse. The sorbent material reacts with the SO_2 in the gas stream and is collected on filter bags. Filter bags are more popular than ESPs since there is evidence that the removal reaction between SO_2 and the sorbent material takes place, in large part, on the bag surface. The reacted sorbent is disposed of after periodic baghouse cleanings. The typical control efficiency range for Dry Sorbent Duct Injection is from 50 to 90 percent (EPA, 1997; Smith, et al., 1994; Soud, 1993; Sondreal, 1993; Torrens, 1990; EPA, 1981).

Wet FGD systems are a general category of control device in which, for SO_2 control, a liquid solution or liquid/solid slurry is used to absorb, and, in most cases, react with SO_2 in a waste gas stream. A scrubbing vessel, into which both the solution or slurry and the waste gas are introduced, is used to maximize the contact between the SO_2 in the waste gas and the reacting compounds in the solution or slurry (EPA, 1981).

The design of the scrubbing vessel and the manner in which the waste gas and the solution or slurry are introduced to the vessel are the means by which the reagent contact is controlled. Types of wet scrubber designs include: tray-type column, packed-bed column, mobile-bed column, venturi, and spray tower. Reagents used in wet scrubber systems include: calcium oxide (from lime), calcium carbonate (from limestone), magnesium oxide, sodium carbonate (soda ash), sodium hydroxide (caustic), sodium citrate, and ammonium hydroxide. Some wet scrubbing systems use a reagent which can be treated and reused and/or produces a saleable product, while other wet systems require that the spent reagent be treated and disposed of appropriately (EPA, 1981).

Wet FGD systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables. The lime and limestone wet scrubbing processes use a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible (EPA, 1997).

Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible (EPA, 1997).

Costs for FGD systems are often expressed in dollars per energy output in kilowatts. Capital costs for spray drying systems generally fall within the range of $140 to $200 (1990 dollars) per kilowatt. Operating costs for spray drying systems are between $300 and $550 (1990 dollars) per ton of SO_2 controlled. Annual costs were estimated using a 15-year equipment lifetime without the effects of inflation (Soud, et al., 1993, Smith, et al., 1994; Radcliffe, 1992; Torrens, 1990).

Capital costs for sorbent injection systems generally fall within the range of $80 to $120 (1990 dollars) per kilowatt. Operating costs for wet scrubbing systems are between $500 and $720 (1990 dollars) per ton of SO_2 controlled. Annual costs were estimated using a 15-year equipment lifetime without the effects of inflation (Soud, et al., 1993, Smith, et al., 1994; Radcliffe, 1992; Torrens, 1990).

Capital costs for wet scrubbing systems generally fall within the range of $180 to $260 (1990 dollars) per kilowatt. Operating costs for wet scrubbing systems are between $460 and $620 (1990 dollars) per ton of SO_2 controlled. Annual costs were estimated using a 15-year equipment lifetime without the effects of inflation (Soud, et al., 1993, Smith, et al., 1994; Radcliffe, 1992; Torrens, 1990).

15.   Steam Generating Unit – Coal/Oil

Gaseous SO_x from coal and oil combustion are primarily SO_2, with a much lower quantity of SO_3 and gaseous sulfates. These compounds form as the organic sulfur in both coal and oil, as well as pyritic sulfur in coal are oxidized during the combustion process. Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size, burner design, or grade of fuel being fired. On average, about 95 percent of the sulfur present in bituminous coal or oil will be emitted as gaseous SO_2, whereas somewhat less will be emitted when subbituminous coal is fired. About 1 to 5 percent of the sulfur in oil is further oxidized to SO_3, and 1 to 3 percent is emitted as sulfate particulate. SO_3 readily reacts with water vapor (both in the atmosphere and in flue gases) to form a sulfuric acid mist. The more alkaline nature of the ash in some subbituminous coals causes some of the sulfur to react in the furnace to form various sulfate salts that are retained in the boiler or in the flyash. Emissions from these sources are not classified under any single identifiable SCC (EPA, 1997).

a.   Description of Available Control Options

Several techniques are used to reduce SO_2 emissions from coal and oil combustion. One way is to switch to lower sulfur coals or oils, since SO_2 emissions are proportional to the sulfur content of the fuel. This alternative may not be possible where lower sulfur fuel is not readily available or where a different grade of fuel cannot be satisfactorily fired. In some cases, various coal cleaning processes may be employed to reduce the sulfur content. Physical coal cleaning removes mineral sulfur such as pyrite but is not effective in removing organic sulfur.

Processes are being developed to remove organic sulfur from coal using chemical cleaning and solvent refining (EPA, 1997).

Post-combustion FGD techniques can remove SO_2 formed during combustion by using an alkaline reagent to absorb SO_2 in the flue gas. Flue gases can be treated using wet, dry, or semi-dry desulfurization processes of either the throwaway type (in which all was streams are discarded) or the recovery/regenerable type (in which the SO_2 absorbent is regenerated and reused). To date, wet systems are the most commonly applied (EPA, 1997).

b.   Control Options Selected for Analysis

Emission control and cost data for wet FGD scrubbing systems applied to industrial steam generation by combustion of bituminous/subbituminous coal were determined from EPA documents and recent technical literature. Wet FGD systems are a general category of control device in which, for SO_2 control, a liquid solution or liquid/solid slurry is used to absorb, and, in most cases, react with SO_2 in a waste gas stream. A scrubbing vessel, into which both the solution or slurry and the waste gas are introduced, is used to maximize the contact between the SO_2 in the waste gas and the reacting compounds in the solution or slurry (EPA, 1981).

The design of the scrubbing vessel and the manner in which the waste gas and the solution or slurry are introduced to the vessel are the means by which the reagent contact is controlled. Types of wet scrubber designs include: tray-type column, packed-bed column, mobile-bed column, venturi, and spray tower. Reagents used in wet scrubber systems include: calcium oxide (from lime), calcium carbonate (from limestone), magnesium oxide, sodium carbonate (soda ash), sodium hydroxide (caustic), sodium citrate, and ammonium hydroxide. Some wet scrubbing systems use a reagent which can be treated and reused and/or produces a saleable product, while other wet systems require that the spent reagent be treated and disposed of appropriately (EPA, 1981).

Wet FGD systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_2. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables. The lime and limestone wet scrubbing processes use a slurry of calcium oxide or limestone to absorb SO_2 in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible (EPA, 1997).

Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO_2 from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO_2 removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO_2 removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO_2 removal efficiencies of 90 to 96 percent are possible (EPA, 1997).

Costs for FGD systems are often expressed in dollars per energy output in kilowatts. Capital costs for wet scrubbing systems generally fall within the range of $180 to $260 (1990 dollars) per kilowatt. Annualized cost effectiveness estimates for wet scrubbing systems given by articles in scientific journals range from $340 to $630 (1990 dollars) per ton of SO_2 controlled. Annual costs were estimated using a 15-year equipment lifetime without the effects of inflation (Soud, et al., 1993, Smith, et al., 1994; Radcliffe, 1992; Torrens, 1990).

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CHAPTER V
STATIONARY SOURCE PM$_{10}$ AND PM$_{2.5}$

This chapter discusses control options for stationary sources of direct particulate emissions (PM$_{10}$ and PM$_{2.5}$). The first section discusses options for point source emitters. The second section discusses area source emitters.

A.   POINT SOURCE PM CONTROL MEASURES

Control efficiencies and costs of systems used to control PM emissions from point sources are based on the use of dry and wet ESPs, fabric filters, venturi scrubbers, and impingement plate scrubbers. These add-on controls are in general use and have been for a number of years, although improvements are continually implemented.

Control efficiency and cost data for control technologies were based on information taken from various sources and professional judgement. Sources include primarily EPA documents, and other agency documents.

The reference used for PM$_{10}$ and PM$_{2.5}$ control efficiencies throughout this section is "Evaluation of Fine Particulate Matter Control Technology" (EC/R, 1996). This document is a compilation of data on achievable emissions reductions for major emission source categories. This document was selected because data for "maximum potential control efficiency" for both PM$_{10}$ and PM$_{2.5}$ for each specific source/control combination are presented.

The primary references for cost data are the Air Pollution Technology Factsheets posted on EPA's OAQPS, Clean Air Technology Center (CATC) website, www.epa.gov/ttn/ catc/cica/cicaeng.html (EPA, 1999a). The factsheets present a complete overview of each control technology; describing the applicable pollutants, achievable emission limits/reductions, industrial applications, emission stream characteristics, cost information, theory of operation, and advantages and disadvantages of each control device. The range of high and low capital costs and O&M costs presented in the factsheets were calculated based on the OAQPS Control Cost Manual and associated spreadsheets (EPA, 1996). The low costs are representative of equipment sized based on the maximum flow rate recommended in the cost manual, with no exotic materials. The high costs are representative of equipment sized based on the minimum flow rate recommended in the cost manual, with no exotic materials. No optional pre- or post treatment equipment costs are included. Unless otherwise noted, costs are based on third quarter 1995 dollars.

The cost estimates are approximate; many control technologies are highly dependent upon specific application needs and varying inlet conditions, which may result in a wide range of values of cost per ton of pollutant controlled.

When stack gas flow rate data was available, the costs and cost effectiveness were calculated using the typical values of normalized capital and O&M costs listed in Table V-1. Total annualized costs were determined by adding the annualized O&M costs; fixed capital recovery charges; and a fixed annual charge for taxes, insurance, and administrative costs. The fixed annual charge for taxes, insurance, and administrative costs was estimated as 4 percent of the total capital investment (EPA, 1990). Total installed capital costs were annualized using a capital recovery factor, which is based on a 7 percent discount rate and the expected life of the control equipment. When stack gas flow rate data was not available, default typical capital and O&M cost values based on tons per year of PM removed were used. The typical cost effectiveness values ($ per ton of PM removed) listed in Table V-1 were also used as default values when stack gas flow rate data was not available.

Table V-2 lists the applicable SCCs for the various PM groups. For each of these PM groups, PM control costs and cost effectiveness values were obtained.

1.   Cement Manufacturing (Wet and Dry Process)

Portland cement plants produce portland cement powder, which is a mixture of calcium silicates, calcium aluminate, calcium aluminoferrite, and calcium aluminate. Portland cement is used in most construction activities. The largest source of particulate emissions at a cement plant is the kiln used to produce clinker. Cement kilns are rotary kilns, which are slowly rotating refractory-lined steel cylinders inclined slightly from the horizontal. Raw materials are fed into the top end of the kiln and spend several hours traversing the kiln. In wet process kilns (SCC 30500706), the raw materials are fed as a wet slurry. During this time, the raw materials are heated by a flame at the discharge end of the kiln. This heating dries the raw materials, converts limestone to lime, and promotes reaction between and fusion of the separate ingredients to form clinker. Clinker exiting the kiln is fed to a clinker cooler (SCC 30500714) for cooling before storage and further processing (STAPPA/ALAPCO, 1996).

a.   Description of Available Control Options

Particulate emissions from cement kilns are typically controlled using dry ESPs or fabric filters. These control options are considered below. Given high inlet loadings and required performance, both devices must be relatively large. Thus, a typical cement kiln baghouse air-to-clothe ratio would be 1.5 feet per minute (ft/min) and a typical precipitator specific collection area would be 350-500 ft^2/1,000 acfm. Kiln gas flows are on the order of 50,000 to 300,000 acfm (STAPPA/ALAPCO, 1996). Clinker coolers may have significant uncontrolled emissions. While most of the air flow through the clinker cooler serves as preheated air for the cement kiln, additional air used to cool the clinker further is vented to the atmosphere. Typical vent stream flows may be 20,000 - 100,000 acfm and may have particulate loadings of 10 - 20 g/m^3, only 10 percent of which is PM_{10} or finer. ESPs and fabric filters provide control of clinker cooler PM emissions to below 50 mg/m^3. ESPs used for this purpose will specific collection areas of 450 - 500 ft^3/acfm and baghouses will have air-to-cloth ratios of 2 ft/min if reverse air and 5 ft/min if pulse jet.

b.   Control Options Selected for Analysis

Control options, efficiencies (EC/R, 1996), and cost data are presented in Table V-1.

Table V-1
Stationary PM Controls and Cost Estimates

PM Group	Source Category/Control Measure	Control Strategy	Control Type (Assumed for Cost Estimate)	PM$_{10}$ Control Efficiency[1]	PM$_{2.5}$ Control Efficiency[1]	Capital Costs[2] ($/scfm)			O&M Costs[2] ($/scfm)			Annualized Costs[2] ($/scfm)			Cost Effectiveness[2] ($/ton PM Removed)		
						Min	Max	Typical	Min	Max	Typical	Min	Max	Typical	Min	Max	Typical
	Cement Manufacturing																
	Wet Process:	1															
21	Portland (Construction) Cement - Kiln; Clinker Cooler																
			Dry ESP-Wire Plate Type	98	95	$15	$50	$27	$4	$40	$16	$5	$40	$17	$40	$250	$110
		2	Fabric Filter (Mech. Shaker Type)	99.5	99	$15	$150	$60	$3	$21	$9	$5	$50	$20	$36	$340	$137
	Dry Process:																
22	Portland (Construction) Cement - Kiln; Clinker Cooler; Ore Crushing; Grinding/Screening																
		1	Fabric Filter (Mech. Shaker Type)	99.5	99	$15	$150	$60	$3	$21	$9	$5	$50	$20	$37	$320	$131
31	Wood/Bark Waste (Industrial Boilers)																
	Wet scrubber	1	Venturi Scrubber	93	92	$3	$28	$11	$4	$119	$42	$5	$123	$44	$76	$2,100	$751
	Stone Quarrying - Processing																
41	Nonmetallic Mineral Processing - Ore Crushing; Grinding/Screening																
			Fabric Filter (Mech. Shaker Type)	99	99	$15	$150	$60	$3	$21	$9	$5	$50	$20	$37	$320	$131
42	Calciners and Dryers																
	NSPS (Venturi scrubber technology)	1	Venturi Scrubber	95	90	$3	$28	$11	$4	$119	$42	$5	$123	$44	$76	$2,100	$751
	Fabric filter	2	Fabric Filter (Mech. Shaker Type)	99	99	$15	$150	$60	$3	$21	$9	$5	$50	$20	$37	$320	$131
	High pressure drop scrubber	3	High pressure drop scrubber	99.9	86	$3	$28	$11	$4	$119	$42	$5	$123	$44	$76	$2,100	$751
	Taconite Iron Ore Processing																
51	Metallic Mineral Processing																
	NSPS (Wet scrubbing or baghouse technology)	1	Fabric Filter (Mech. Shaker Type)	99	99	$15	$150	$60	$3	$21	$9	$5	$50	$20	$37	$320	$131
	Bituminous/Subbituminous Coal (Industrial Boilers)																
61	ICI Steam Generation																
	Wet (venturi) scrubbers	1	Venturi Scrubber	82	50	$3	$28	$11	$4	$119	$42	$5	$123	$44	$76	$2,100	$751

Table V-1 (continued)

PM Group	Source Category/Control Measure	Control Strategy	Control Type (Assumed for Cost Estimate)	PM$_{10}$ Control Efficiency[1]	PM$_{2.5}$ Control Efficiency[1]	Capital Costs[2] ($/scfm)			O&M Costs[2] ($/scfm)			Annualized Costs[2] ($/scfm)			Cost Effectiveness[2] ($/ton PM Removed)		
						Min	Max	Typical	Min	Max	Typical	Min	Max	Typical	Min	Max	Typical
		2	Dry ESP-Wire Plate Type	98	95	$15	$50	$27	$4	$40	$16	$5	$40	$17	$40	$250	$110
	NSPS (Baghouse or ESP technology for large sources and wet scrubber technology for small sources)	3	Fabric Filter (Mech. Shaker Type)	99	99	$15	$150	$60	$3	$21	$9	$5	$50	$20	$37	$320	$131
	Coal Mining, Cleaning, and Material Handling																
71	Coal Preparation Plants - Thermal Dryers																
	NSPS (Centrifugal collectors to venturi scrubber technology)	1	Venturi Scrubber	99	98	$3	$28	$11	$4	$119	$42	$5	$123	$44	$76	$2,100	$751
72	Coal Preparation Plants - Pneumatic Coal Cleaning																
	NSPS (Collectors to fabric filter technology)	2	Fabric Filter (Mech. Shaker Type)	99.5	99	$15	$150	$60	$3	$21	$9	$5	$50	$20	$37	$320	$131
	Steel Manufacturing																
	Iron and Steel - Basic Oxygen Process Furnace																
81	NSPS (Closed hood/venturi scrubber technology)	1	Venturi Scrubber	73	25	$3	$28	$11	$4	$119	$42	$5	$123	$44	$76	$2,100	$751
82	Steel Production-EAF Argon O2 Decarb Vessels																
	NSPS (Hood/fabric filter technology)	1	Fabric Filter (Mech. Shaker Type)	99.9	99.9	$15	$150	$60	$3	$21	$9	$5	$50	$20	$37	$320	$131
	Iron Production																
92	Metallic Mineral Processing																
	NSPS (Wet scrubbing or baghouse technology)	1	Venturi Scrubber	73	25	$3	$28	$11	$4	$119	$42	$5	$123	$44	$76	$2,100	$751
		2	Fabric Filter (Mech. Shaker Type)	99	99	$15	$150	$60	$3	$21	$9	$5	$50	$20	$37	$320	$131
101	By-product Coke Manufacturing																
	Fabric filter	1	Fabric Filter (Mech. Shaker Type)	92	92	$15	$150	$60	$3	$21	$9	$5	$50	$20	$37	$320	$131
	Venturi scrubber	2	Venturi Scrubber	93	89	$3	$28	$11	$4	$119	$42	$5	$123	$44	$76	$2,100	$751
	Wet ESP	3	Wet ESP - Wire Plate Type	99	99	$30	$60	$40	$6	$45	$19	$10	$50	$23	$55	$550	$220
111	Residual Oil (Industrial Boilers)																
	Wet scrubbers	1	Venturi Scrubber	92	89	$3	$28	$11	$4	$119	$42	$5	$123	$44	$76	$2,100	$751

Table V-1 (continued)

PM Group	Source Category/Control Measure	Control Strategy	Control Type (Assumed for Cost Estimate)	PM$_{10}$ Control Efficiency[1]	PM$_{2.5}$ Control Efficiency[1]	Capital Costs[2] ($/scfm)			O&M Costs[2] ($/scfm)			Annualized Costs[2] ($/scfm)			Cost Effectiveness[2] ($/ton PM Removed)		
						Min	Max	Typical	Min	Max	Typical	Min	Max	Typical	Min	Max	Typical
	Fiberglass Manufacturing																
121	Wool Fiberglass Manufacturing-Rotary Spin																
	NSPS (Wet ESP technology)	1	Wet ESP - Wire Plate Type	99	95	$30	$60	$40	$6	$45	$19	$10	$50	$23	$55	$550	$220
122	Glass Manufacturing Plants - Furnace																
	NSPS (ESP technology)	1	Dry ESP-Wire Plate Type	99	99	$15	$50	$27	$4	$40	$16	$5	$40	$17	$40	$250	$110
131	Feed and Grain Country Elevators																
	Fabric filters	1	Fabric Filter (Mech. Shaker Type)	99	99	$15	$150	$60	$3	$21	$9	$5	$50	$20	$37	$320	$131
141	Grey Iron Foundries																
	Impingement scrubber	1	Impingement-plate	64	64	$3	$71	$26	$3	$71	$26	$3	$71	$26	$46	$1,200	$431
	ESP	2	Dry ESP-Wire Plate Type	90	90	$15	$50	$27	$4	$40	$16	$5	$40	$17	$40	$250	$110
	Fabric filter	3	Fabric Filter (Mech. Shaker Type)	94	93	$15	$150	$60	$3	$21	$9	$5	$50	$20	$36	$340	$137
	High energy scrubber	4	Venturi Scrubber	94	94	$3	$28	$11	$4	$119	$42	$5	$123	$44	$76	$2,100	$751
	Catalytic Cracking Units																
151	Petroleum Refineries - FCCU																
	NSPS (ESP technology)	1	Dry ESP-Wire Plate Type	82-99	82	$15	$50	$27	$4	$40	$16	$5	$40	$17	$40	$250	$110
	Feed and Grain Terminal Elevators																
161	Grain Elevators																
	NSPS (Fabric filter technology)	1	Fabric Filter (Mech. Shaker Type)	99	99	$15	$150	$60	$3	$21	$9	$5	$50	$20	$36	$340	$137
	Glass Manufacture																
171	Glass Manufacturing Plants - Furnace																
	NSPS (ESP technology)	1	Dry ESP-Wire Plate Type	99	99	$15	$50	$27	$4	$40	$16	$5	$40	$17	$40	$250	$110

Table V-1 (continued)

PM Group	Source Category/Control Measure	Control Strategy	Control Type (Assumed for Cost Estimate)	PM_{10} Control Efficiency[1]	$PM_{2.5}$ Control Efficiency[1]	Capital Costs[2] ($/scfm)			O&M Costs[2] ($/scfm)			Annualized Costs[2] ($/scfm)			Cost Effectiveness[2] ($/ton PM Removed)		
						Min	Max	Typical	Min	Max	Typical	Min	Max	Typical	Min	Max	Typical
172	Nonmetallic Mineral Processing - Crushing/Grinding																
	NSPS (Fabric filter technology)	1	Fabric Filter (Pulse Jet Type)	99	99	$5	$130	$47	$4	$20	$9	$4	$45	$18	$29	$300	$119
	Plywood/Particleboard Operations																
181	Veneer Dryers																
	Wet scrubber system (spray chamber, cyclonic collector and packed bed scrubber in series)	1	Packed bed scrubber x 1.5	95	91	$16	$84	$39	$24	$108	$52	$26	$117	$56	$73	$328	$244
182	Waferboard Dryers																
	Wet ESP	1	Wet ESP - Wire Plate Type	90-99		$30	$60	$40	$6	$45	$19	$10	$50	$23	$55	$550	$220
	Asphalt Concrete																
191	Hot Mix Asphalt Plants																
	NSPS (Fabric filter or venturi scrubber technology)	1	FF - MS/RA	99	99	$15	$150	$60	$3	$21	$9	$5	$50	$20	$36	$340	$137

SOURCES: [1]EC/R, 1996.
[2]EPA, 1999a.

Table V-2
Stationary Point Source PM Groups and SCCs

SCC	PM Group	PM Group Name
30500706	21	Cement Manufacturing - Wet Process
30500714	21	Cement Manufacturing - Wet Process
30500606	22	Cement Manufacturing - Dry Process
30500614	22	Cement Manufacturing - Dry Process
30500609	22	Cement Manufacturing - Dry Process
30500611	22	Cement Manufacturing - Dry Process
30500613	22	Cement Manufacturing - Dry Process
10200901	31	Wood/Bark Waste (Industrial Boilers)
10200902	31	Wood/Bark Waste (Industrial Boilers)
10200903	31	Wood/Bark Waste (Industrial Boilers)
10200904	31	Wood/Bark Waste (Industrial Boilers)
10200905	31	Wood/Bark Waste (Industrial Boilers)
10200906	31	Wood/Bark Waste (Industrial Boilers)
10200907	31	Wood/Bark Waste (Industrial Boilers)
30502001	41	Stone Quarrying - Processing
30502004	41	Stone Quarrying - Processing
30502012	42	Stone Quarrying - Processing
30302301	51	Taconite Iron Ore Processing
30302302	51	Taconite Iron Ore Processing
30302303	51	Taconite Iron Ore Processing
30302304	51	Taconite Iron Ore Processing
30302306	51	Taconite Iron Ore Processing
30302311	51	Taconite Iron Ore Processing
10200201	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200202	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200203	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200204	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200205	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200206	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200212	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200213	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200217	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200219	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200221	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200222	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200223	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200224	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200225	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200226	61	Bituminous/Subbituminous Coal (Industrial Boilers)
10200229	61	Bituminous/Subbituminous Coal (Industrial Boilers)
30501001	71	Coal Mining, Cleaning, and Material Handling
30501002	71	Coal Mining, Cleaning, and Material Handling
30501003	71	Coal Mining, Cleaning, and Material Handling
30501004	71	Coal Mining, Cleaning, and Material Handling
30501005	71	Coal Mining, Cleaning, and Material Handling
30501006	71	Coal Mining, Cleaning, and Material Handling
30501007	71	Coal Mining, Cleaning, and Material Handling
30501013	72	Coal Mining, Cleaning, and Material Handling
30300914	81	Steel Manufacturing
30300928	82	Steel Manufacturing
30300812	92	Iron Production
30300818	92	Iron Production
30300820	92	Iron Production
30300821	92	Iron Production
30300823	92	Iron Production
30300827	92	Iron Production

Table V-2 (continued)

SCC	PM Group	PM Group Name
30300842	92	Iron Production
30300302	101	By-product Coke Manufacturing
30300303	101	By-product Coke Manufacturing
30300304	101	By-product Coke Manufacturing
30300305	101	By-product Coke Manufacturing
30300306	101	By-product Coke Manufacturing
30300307	101	By-product Coke Manufacturing
30300308	101	By-product Coke Manufacturing
30300309	101	By-product Coke Manufacturing
30300310	101	By-product Coke Manufacturing
30300311	101	By-product Coke Manufacturing
30300312	101	By-product Coke Manufacturing
30300313	101	By-product Coke Manufacturing
30300314	101	By-product Coke Manufacturing
30300315	101	By-product Coke Manufacturing
30300316	101	By-product Coke Manufacturing
30300401	101	By-product Coke Manufacturing
10200401	111	Residual Oil (Industrial Boilers)
10200404	111	Residual Oil (Industrial Boilers)
10200405	111	Residual Oil (Industrial Boilers)
30501204	121	Fiberglass Manufacturing
30501205	121	Fiberglass Manufacturing
30501201	122	Fiberglass Manufacturing
30501202	122	Fiberglass Manufacturing
30501203	122	Fiberglass Manufacturing
30501207	122	Fiberglass Manufacturing
30501211	122	Fiberglass Manufacturing
30501212	122	Fiberglass Manufacturing
30501213	122	Fiberglass Manufacturing
30200603	131	Feed and Grain Country Elevators
30200604	131	Feed and Grain Country Elevators
30200605	131	Feed and Grain Country Elevators
30200606	131	Feed and Grain Country Elevators
30200607	131	Feed and Grain Country Elevators
30200608	131	Feed and Grain Country Elevators
30200609	131	Feed and Grain Country Elevators
30200610	131	Feed and Grain Country Elevators
30200611	131	Feed and Grain Country Elevators
30200699	131	Feed and Grain Country Elevators
30400301	141	Grey Iron Foundries
30400302	141	Grey Iron Foundries
30400303	141	Grey Iron Foundries
30400304	141	Grey Iron Foundries
30400310	141	Grey Iron Foundries
30400315	141	Grey Iron Foundries
30400320	141	Grey Iron Foundries
30400325	141	Grey Iron Foundries
30400331	141	Grey Iron Foundries
30400340	141	Grey Iron Foundries
30400350	141	Grey Iron Foundries
30400351	141	Grey Iron Foundries
30400352	141	Grey Iron Foundries
30400353	141	Grey Iron Foundries
30400360	141	Grey Iron Foundries
30600201	151	Catalytic Cracking Units
30600202	151	Catalytic Cracking Units
30600204	151	Catalytic Cracking Units

Table V-2 (continued)

SCC	PM Group	PM Group Name
30600301	151	Catalytic Cracking Units
30200501	161	Feed and Grain Terminal Elevators
30200502	161	Feed and Grain Terminal Elevators
30200503	161	Feed and Grain Terminal Elevators
30200504	161	Feed and Grain Terminal Elevators
30200505	161	Feed and Grain Terminal Elevators
30200506	161	Feed and Grain Terminal Elevators
30200507	161	Feed and Grain Terminal Elevators
30200508	161	Feed and Grain Terminal Elevators
30200509	161	Feed and Grain Terminal Elevators
30200510	161	Feed and Grain Terminal Elevators
30200511	161	Feed and Grain Terminal Elevators
30200512	161	Feed and Grain Terminal Elevators
30501401	171	Glass Manufacture
30501402	171	Glass Manufacture
30501403	171	Glass Manufacture
30501404	171	Glass Manufacture
30501414	171	Glass Manufacture
30501413	172	Glass Manufacture
30700713	181	Plywood/Particleboard Operations
30700715	181	Plywood/Particleboard Operations
30700716	181	Plywood/Particleboard Operations
30700704	182	Plywood/Particleboard Operations
30500202	191	Asphalt Concrete
30500205	191	Asphalt Concrete

2.   Wood/Bark Waste (Industrial Boilers)

The burning of wood and bark waste in boilers is mostly confined to industries where wood and bark waste is available as a byproduct. Wood and bark waste is burned to obtain heat energy and to alleviate possible solid waste disposal problems. In boilers, the waste is burned in the form of hogged wood, sawdust, shavings, chips, sanderdust, or wood trim. Bark is the major type of waste burned in "power" boilers at pulp and paper mills. At lumber, furniture, and plywood plants, either a mixture of wood and bark waste or wood waste alone is burned most frequently (EPA, 1995).

Wood- and bark-waste fired boilers (SCC 10200901, Bark, >50K lb steam; 10200902, Wood/Bark, >50K lb steam; and 10200903, Wood, >50K lb steam) are significant sources of PM_{10} and $PM_{2.5}$ emissions.

a.   Description of Available Control Options

According to AP-42, the four most common control devices used to control PM emissions from wood- or bark-waste fired boilers are cyclones, wet scrubbers, ESPs, and fabric filters. Cyclones use centrifugal force to mechanically separate particulates from gas streams. As the flow stream passes through the cyclone, PM is impinged on the walls of the unit and fall into a collection bin. Multitube cyclones (or multiclones) provide PM control for many hogged boilers. Two multiclones are often used in series where the first unit collects the bulk of the dust and the second unit collects smaller particles passing through the first unit. The total suspended particulate (TSP) control efficiency of two multiclones in series ranges from 65 to 95 percent (EPA, 1995).

Scrubbers remove particulates by collecting them in liquid droplets. Venturi scrubbers, with gas-side pressure drops exceeding 15 inches of water column, are the most widely used type of scrubber for wood and bark fired boilers. Venturi scrubbers of this type can achieve TSP control efficiencies of 90 percent or more (EPA, 1995).

ESPs are used when control efficiencies of 95 percent or more are required. ESPs use electrical fields to remove particulate from boiler flue gas. An intense electric field is maintained between high-voltage discharge electrodes. An electric discharge ionizes the gas passing through the ESP, and these gas ions ionize fly ash or other particulates. The collector plates are periodically mechanically cleaned to remove the collected particulates (EPA, 1995; STAPPA/ALAPCO, 1993). ESPs are often used downstream of a cyclone, which removes larger-sized dust particles. ESPs can achieve TSP control efficiencies by approximately 90 percent (STAPPA/ALAPCO, 1996).

According to AP-42, fabric filters are also used when control efficiencies of 95 percent or more are required. However, fabric filters have had limited applications to wood and bark fired boilers because of a potential fire danger (as perceived by potential users) associated with the collection of combustible carbonaceous fly ash. To reduce this potential hazard, mechanical collectors can be installed upstream of the fabric filter to remove large burning particles of fly ash. Fabric filters are generally preferred for boilers firing salt-laden wood, which produces fine particles with a high salt content (EPA, 1995).

b.   Control Options Selected for Analysis

Multiple cyclones and Venturi scrubbers were modeled as a control option for reducing PM emissions from wood- and bark-waste fired boilers.

Control efficiencies and estimated cost data are presented in Table V-1.

3.   Stone Quarrying - Processing

Nonmetallic Mineral Processing (305020) - ore crushing, grinding, and screening, and Calciners (SCC 305150) and Dryers (SCC 30502012) are considered in this

category. Materials handling operations including crushing, grinding, and screening, can produce significant PM emissions. Drying, the heating of minerals or mineral products to remove water, and calcination, heating to higher temperatures to remove chemically bound water and other compounds, are normally performed in dedicated, closed units. Emissions from these units will be through process vents, to which PM controls can be applied relatively simply. Fugitive dust emissions may come from paved and unpaved roads in plants and from raw material and product loading, unloading, and storage (STAPPA/ALAPCO, 1996).

a. Description of Available Control Options

In 1980, EPA published a background information document (BID) for proposed NSPS for nonmetallic mineral processing plants (EPA, 1980). According to the BID, fabric filtration is the predominant control technique used to control PM emissions from mineral ore crushing, grinding, and screening operations. Other control techniques used by controlled emission sources include gravity collectors, cyclones, electrostatic precipitators, wet and venturi scrubbers, water spray, process enclosure, and many different combinations of these control techniques.

b. Control Options Selected for Analysis

Fabric filters, high pressure drop scrubbers, Venturi scrubbers, cyclone/fabric filter combinations, and multicyclone/wet scrubber combinations control technologies were selected as the basis for estimating the emission reductions and costs of controlling PM_{10} and $PM_{2.5}$ emissions from calciners and dryers.

Fabric filters were selected as the basis for estimating the emission reductions and costs of controlling PM_{10} and $PM_{2.5}$ emissions from sources of crushing, grinding, and screening operations. Control efficiencies and estimated cost data are presented in Table V-1.

4. Taconite Iron Ore Processing

Taconite iron ore processing involves the production of fluxed iron ore pellets from the initial ground excavation to the final stage of shipping. The process is composed of six interrelated operations: mining of the ore, ore crushing, ore concentrating, fluxstone processing, pelletizing, and shipping. Crushing, concentrating, fluxstone processing, and pelletizing generate fugitive PM emissions which are collected by local hoods and ducted to a control device.

a. Description of Available Control Options

Two types of control equipment are used for the control of fugitive PM that can be collected with hoods: the fabric filters and wet scrubbers.

b. Control Options Selected for Analysis

The fabric filter is selected for analysis. It provides a high level of control than wet scrubbing. Control efficiencies and estimated cost data are presented in Table V-1.

5. Bituminous/Subbituminous Coal (Industrial Boilers)

There are two major coal combustion techniques in industrial boilers - suspension firing and grate firing. Suspension firing is the primary combustion mechanism in pulverized-coal-fired and cyclone-fired units and overfeed stoker-fired units. Both mechanisms are employed in spreader stokers. Pulverized-coal and cyclone furnaces are used primarily in utility and large industrial boilers.

Stokers constitute the most practical method of firing coal for small industrial units. In spreader stokers, a flipping mechanism throws the coal into the furnace and onto a moving fuel bed. Combustion occurs partly in suspension and partly on the grate. In overfeed stokers, coal is fed onto a traveling bed or vibrating grate, and it burns on the fuel bed as it progresses through the furnace (AWMA, 1992).

Particulate composition and emission levels are a complex function of firing configuration, boiler operation, and coal properties. In pulverized-coal systems, combustion is almost complete, and thus the particulate is largely composed of the inorganic ash residue. Because of a mixture of fine and coarse coal particles is fired in spreader stokers, significant unburned carbon can be present in the particulate. To improve efficiency, fly ash from collection devices (typically multiple cyclones) is sometimes reinjected into spreader stoker furnaces, which can dramatically increase PM emissions. Uncontrolled overfeed and underfeed stokers emit considerably less particulate than do pulverized-coal units and spreader stokers, since combustion takes place in a relatively quiescent fuel bed. Variables other than firing configuration and fly-ash reinjection can also affect emissions from stokers. Particulate loadings will often increase as load increases and with sudden load changes. PM can increase as the ash and fines contents increase (AWMA, 1992).

a. Description of Available Control Options

The primary types of PM control used for coal combustion are multiple cyclones, ESPs, fabric filters, and venturi scrubbers.

b. Control Options Selected for Analysis

Venturi scrubbers (small sources) and fabric filters and dry ESPs (large sources) are selected for analysis. Control efficiencies and estimated cost data are presented in Table V-1.

6. Coal Mining, Cleaning, and Material Handling

Coal mining, cleaning and material handling (305010) consists of the preparation and handling of coal to upgrade its value. For the purpose of this study, thermal dryers, pneumatic coal cleaning and truck/vehicle travel are the sources considered. Thermal dryers are used at the end of the series of cleaning operations to remove moisture from coal, thereby reducing freezing problems and weight, and increasing the heating value. The major portion of water is removed by the use of screens, thickeners, and cyclones. The coal is then dried in a thermal dryer. Particulate emissions result from the entrainment of fine coal particles during the thermal drying process (EPA, 1995). Pneumatic coal-cleaning equipment classifies bituminous coal by size or separates bituminous coal from refuse by application of air streams. Fugitive PM emissions result when haul trucks or other vehicles travel on unpaved roads or surfaces.

a. Description of Available Control Options

Particulate emissions from dryers and cleaning are typically controlled using wet suppression, or process enclosure venting to a control device (e.g., venturi scrubber or fabric filter). Potential control options for truck/vehicle travel on unpaved roads include water suppression, speed reduction, chemical treatment, and asphalt paving.

b. Control Options Selected for Analysis

A combination of a centrifugal collectors in series with venturi scrubbers is selected for thermal dryers. A combination of centrifugal collectors in series with fabric filters is selected for pneumatic coal cleaning. Asphalt paving is selected for truck/vehicle travel. Control efficiencies and estimated cost data are presented in Table V-1.

7. Steel Manufacturing

Several processes within this industry were selected for control, Basic Oxygen Process Furnace (SCC 30300914) and EAF Argon O_2 Decarb Vessels (SCC 30300928). Steel normally is produced in either basic oxygen process furnaces or electric arc furnaces. In the basic oxygen process furnace, a mixture of 70 percent molten iron from the blast furnace and 30 percent iron scrap are melted together. Pure oxygen is blown across the top or through the molten steel to oxidize carbon and oxygen impurities, thus removing these from the steel. Basic oxygen process furnaces are large open-mouthed furnaces that can be tilted to accept a charge or to tap the molten steel to a charging ladle for transfer to an ingot mold or continuous caster.

Because basic oxygen furnaces are open, they produce significant uncontrolled particulate emissions, notably during the refining stage when oxygen is being blown. Emissions from these furnaces may be controlled by over 99 percent using either open or closed hoods vented to scrubbers or electrostatic precipitators. Furnace enclosures or local hoods collect emissions during tapping and other operations. The emissions are vented to baghouses which provide greater than 99 percent emissions reductions.

Electric arc furnaces use the current passing between carbon electrodes to heat molten steel, but also use oxy-fuel burners to accelerate the initial melting process. These furnaces are charged largely with scrap iron. Significant emissions occur during charging, when the furnace roof is open, during melting, as the electrodes are lowered into the scrap and the arc is struck, and during tapping, when alloying elements are added to the melt. Direct evacuation of the gases above the molten steel through a water-cooled duct provides good control of particulate emissions, from an uncontrolled level of 50 pounds per ton to a baghouse-controlled level of 0.043 pounds per ton for carbon steel. Particulate generated during charging and tapping normally is captured with a canopy hood.

a. Description of Available Control Options

Control options include fabric filters, wet scrubbers, gravity collectors, and electrostatic precipitators to reduce emissions.

b. Control Options Selected for Analysis

Closed hood/venturi scrubber technology is selected for controlling emissions from the Basic Oxygen Furnace and hood/fabric filter technology is selected for controlling the EAF. Control efficiencies and estimated cost data are presented in Table V-1.

8. Iron Production

The sources of interest in this category are Metallic Mineral Processing (SCC 303008) and Mineral Product and Primary metal Operations - Truck/Vehicle Travel. PM emissions are generated when haul trucks or other vehicles travel on unpaved roads or surfaces.

a. Description of Available Control Options

Potential control options for the mineral processing category includes wet scrubbing and fabric filters. Potential control options for the truck/vehicle travel includes water suppression, speed reduction, chemical treatment and paving.

b. Control Options Selected for Analysis

The control options analyzed for the mineral processing category are wet scrubbing and fabric filters. The control option for the truck/vehicle travel source is paving. Control efficiencies and estimated cost data are presented in Table V-1.

9.   By-product Coke Manufacturing

By product coke production is used to manufacture metallurgical coke by heating high-grade bituminous coal (low sulfur and low ash) in an enclosed oven chamber without oxygen. The resulting solid material consists of elemental carbon and any minerals (ash) that were present in the coal blend that did not volatilize during the process. Sources of air emissions consist of coke oven doors, coke oven lids and off-takes, coke oven charging, coke oven pushing, coke oven underfire stack, coke quenching, battery venting, and coke by-product-recovery plants.

a.   Description of Available Control Options

Potential control options for byproduct coke manufacturing include proper equipment and sealing designs, work practices, maintenance procedures, mobile systems (such as mobile scrubber cars and mobile fume suppression systems), devices connected to land-based pollution controls, such as fabric filters, wet scrubbers, and wet ESPs. Potential control options for the truck/vehicle travel includes water suppression, speed reduction, chemical treatment and paving.

b.   Control Options Selected for Analysis

Control options selected for this category include fabric filters, mobile scrubber cars, stage or sequential charge, venturi scrubbers, and wet ESPs. Control efficiencies and estimated cost data are presented in Table V-1.

10.   Residual Oil (Industrial Boilers)

Heavier fuel oil derived from crude petroleum are referred to as residual oils and are graded from No. 4 (very light residual) to No. 6 (residual). Emissions from fuel oil combustion depend on the grade anc composition of the oil, the type and size of the boiler, firing practices used, and the level of equipment maintenance.

a.   Description of Available Control Options

Potential PM control options for industrial boilers using residual oil include wet scrubbers and ESPs.

b.   Control Options Selected for Analysis

The control option selected for this category is wet scrubbing. Control efficiencies and estimated cost data are presented in Table V-1.

11.   Fiberglass Manufacturing

The production of fiberglass consists of two different forms of product, continuous-filament fiberglass or textile products and fiberglass blown wool or insulation products. The two fiberglass sources considered here are wool fiberglass manufacturing - rotary spin and glass manufacturing plants - furnace.

a.   Description of Available Control Options

Potential PM control options consist of wet scrubbers (packed tower, venturi), and wet and dry ESPs.

b.   Control Options Selected for Analysis

The control options selected for this category are wet ESPs for the wool fiberglass manufacturing - rotary spin and dry ESPs for glass manufacturing plants - furnace. Control efficiencies and estimated cost data are presented in Table V-1.

12. Feed and Grain Terminal and Country Elevators

Grain elevators act as intermediate storage and transfer points for grain as it is transported from the farms to the market. The receiving, handling and transfer, drying, and loading and shipping of grain at elevators generate grain dust which contributes to PM emissions. Grain elevators are classified as either country (SCC 302006), terminal (SCC 302005), or export (SCC 302031). Country elevators accept most of their grain from farms, while terminal elevators accept most of their grain from country elevators and a small portion from farms. Country elevators sometimes clean or dry grain before it is transported to terminal elevators or processors. Terminal elevators dry, clean, blend, and store grain before shipment to other terminals or processors, or for export. Terminal elevators ship their grain to export terminals or directly to processors. Export elevators are terminal elevators that load grain primarily onto ships for export. Country elevators account for 67 percent of total uncontrolled PM_{10} and $PM_{2.5}$ grain elevator emissions in the 1990 NPI. Terminal and export elevators account for 27 and 6 percent of the uncontrolled gain elevator emissions, respectively.

a. Description of Available Control Options

Traditional PM emission controls for grain elevators include cyclones, fabric filters, and dust recirculation. Capture systems are used to capture and convey emissions to cyclones and fabric filters. The high cost of these controls, especially for the smaller country elevators, has generated interest in the use of oil suppression as a less costly method for controlling dust at grain elevators. In 1994, EPA's Control Technology Center (CTC) published a report on the use of oil suppression as an alternative to traditional controls for controlling PM emissions at grain elevators (EPA, 1994). According to the CTC report, oil suppression has been used worldwide for more than a decade to control dust at small country elevators as well as large export terminals. Use of oil to control dust has been approved by the Food and Drug Administration for wheat, corn, soybeans, barley, rice, rye, oats, and sorghum (21 CFR 172.878).

b. Control Options Selected for Analysis

Oil suppression can provide 75 to 99 percent control of TSP emissions. While the oil suppression system is favored because of costs, for the purpose of this study, fabric filters are being considered because they can achieve greater than 99 percent control of TSP as well as small and light particles. Control efficiencies and estimated cost data are presented in Table V-1.

13. Grey Iron Foundries

Grey iron is an alloy of iron, carbon, and silicon, containing a higher percentage of the last two elements than found in malleable iron. The high strengths are obtained by the proper adjustment of the carbon and silicon contents or by alloying.

a. Description of Available Control Options

Two primary collection methods are used for foundry particulates - wet and dry. Wet scrubbers include low- and high energy types. Dry collection includes fabric filters, mechanical collectors, and ESPs.

b. Control Options Selected for Analysis

The control options selected for this category are dry ESPs, fabric filters, venturi scrubbers, and impingement plate scrubbers. Control efficiencies and estimated cost data are presented in Table V-1.

14.   Catalytic Cracking Units

FCCU contribute over 85 percent of refinery primary particulate emissions. These units are used to convert heavy oils into high-octane gasoline. The fluid catalytic cracking process uses a catalyst in the form of very fine particles that act as a fluid when charged with a vapor. There are two sources of air emissions from catalytic cracking: Process heater and catalyst regenerator.

a.   Description of Available Control Options

ESPs are in common use at refineries for the treatment of FCCU regenerator off-gas. In a typical application, the off-gas is routed through a CO boiler for recovery of the heat value of the gas and then sent to an ESP. Scrubbers are used to separate and purify the fluid catalytic cracking off-gas stream containing high concentrations of VOC, SO_2, and PM. A common system on fluid catalytic cracking regenerators is a caustic scrubber, where PM removal and SO_x absorption takes place in a venturi scrubber. PM is removed by inertial impaction of the scrubbing liquid with the entrained particles (AWMA, 1992).

b.   Control Options Selected for Analysis

The control options selected for this category are dry ESPs, fabric filters, venturi scrubbers, and impingement plate scrubbers. Control efficiencies and estimated cost data are presented in Table V-1.

15.   Glass Manufacture

The three major components of the manufacture of glass are raw material blending and transport, melting, and forming and finishing. The sources of interest in the present study are crushing and grinding of the raw materials, which generate fugitive dust, and the furnace associated with the melting process.

a.   Description of Available Control Options

Pulse jet fabric filters are used for collection of PM emitted at weigh-blending stations (AWMA, 1992). Many types of controls are used for controlling PM and acid gas emissions from glass furnaces: wet scrubbing - venturi and packed bed, fabric filters, ESPs, electric boost, dry scrubbing, semi-dry scrubbing.

b.   Control Options Selected for Analysis

The control options selected for this category are pulse jet fabric filters for crushing and grinding and dry ESPs for furnace emissions. Control efficiencies and estimated cost data are presented in Table V-1.

16.   Plywood/Particleboard Operations

Plywood is a building material consisting of thin veneers (thin wood layers or piles) bonded with an adhesive. The manufacture consists of seven main process; however, the present source of interest is veneer dryers. The term particleboard also is used generically to include waferboard. The source of interest for this product is waferboard dryers.

a.   Description of Available Control Options

PM from plywood veneer dryers includes both filterable and condensible PM. Control options include multiple spray chambers, packed tower combined with a cyclonic collector, sand filter scrubbers, ionizing wet scrubbers, electrified filter beds, and wet ESPs. Methods of controlling PM emissions from the particle dryer include multi-clones, packed bed absorbers, fabric filters, electrified filter beds, wet ESPs, and incinerators (EPA, 1999b).

b.   Control Options Selected for Analysis

At present, multiple spray chambers are the most common control technology used on veneer dryers, however, because they provide only limited removal of PM and condensible organic emissions, they are being replaced with newer, more effective techniques. The packed tower combined with a cyclonic collector is selected for analysis for this source. For the particle dryer, the wet ESP is selected. Control efficiencies and estimated cost data are presented in Table V-1.

17.   Asphalt Concrete

Hot mix asphalt (HMA) paving material is a scientifically proportioned mixture of graded aggregates and asphalt cement. The process of producing involves drying and heating the aggregates to prepare them for the asphalt cement coating.

a.   Description of Available Control Options

Two types of control equipment are used for the control of PM from the HMA mixing process: the fabric filter and the venturi scrubber.

b.   Control Options Selected for Analysis

The fabric filter is selected for analysis. It is more commonly used, and provides a high level of control with less maintenance required than the venturi scrubber (AWMA, 1992). Control efficiencies and estimated cost data are presented in Table V-1.

B.   AREA SOURCE PM CONTROL MEASURES

Control efficiencies and costs of systems used to control PM emissions from area sources usually require a fundamental change in the source or the equipment used, or how the source is operated, rather than simply applying an add-on control.

Control efficiency and cost data for control methodologies were based on information taken from various sources and professional judgement. Sources include EPA documents, other agency documents, and contacts with vendors.

The reference used for PM_{10} and $PM_{2.5}$ control efficiencies throughout this section is "Evaluation of Fine Particulate Matter Control Technology" (EC/R, 1996), unless otherwise noted. This document is a compilation of data on achievable emissions reductions for major emission source categories. This document was selected because data for "maximum potential control efficiency" for both PM_{10} and $PM_{2.5}$ for each specific source/control combination are presented.

The cost estimates are approximate; many control technologies are highly dependent upon specific application needs and varying inlet conditions, which may result in a wide range of values of cost per ton of pollutant controlled. Control efficiencies, and costs as available for each group are presented in Table V-3. Due to the wide variability and uncertainty of emission rates from these sources, no meaningful cost effectiveness data are available.

Thus, this section generally provides measures which may provide reductions in addition to those achieved by measures which have already been assessed (Pechan, 1997). No new control measure parameters have been developed as a result of this investigation. Additional work is needed to determine the overall reduction for an SCC and the cost per ton of emissions reduced.

1. Fugitive Dust - Unpaved Rural Roads

Unpaved roads comprise a sizable percentage of total $PM_{10}/PM_{2.5}$ emissions. Unpaved roads, especially rural roads, do not generally experience the type of traffic volume associated with paved roads.

a. Description of Available Control Options

Many control options exist for reducing PM emissions from unpaved rural roads. These include (1) controlling the source, e.g., through speed reduction; (2) treating the surface, such as through chemical stabilization or road oiling; and (3) improving the surface by adding gravel, or paving. Hot asphalt paving is the control capable of achieving the highest PM reduction from unpaved rural roads. Hot asphalt paving is based on paving materials which meet RACT requirements and thereby do not emit VOCs. Hot asphalt paving is a viable control option for urban areas; however, for rural roads, this control technique does have a high cost relative to the emission reduction potential, due to the fact that there is typically less traffic.

b. Control Options Selected for Analysis

Hot asphalt paving was modeled as the control option for reducing PM emissions. For purposes of control cost modeling, a cost per vehicle miles traveled (VMT) is required. Capital costs were estimated by assuming $90,000 per mile of paving (Rosenberger, 1995). Assuming a 40 year life and a 7 percent discount rate, the capital recovery factor for asphalt paving is 0.075. On an annualized basis, this is equivalent to 0.075 x $90,000/mile = $6,750/mile. Operation and maintenance costs were estimated by

Table V-3
Stationary Area Source PM Controls

Source Category/Control Measure	SCC	Control Type (Assumed for Cost Estimate)	PM$_{10}$ Control Efficiency[1]	PM$_{2.5}$ Control Efficiency[1]	Capital Cost Min	Capital Cost Max	Capital Cost Typical	O&M Cost Min	O&M Cost Max	O&M Cost Typical	Annualized Cost Min	Annualized Cost Max	Annualized Cost Typical	Cost Effec. ($/ton) Min	Cost Effec. ($/ton) Max	Cost Effec. ($/ton) Typical
Fugitive Dust-Unpaved Roads																
Rural Roads	2296000000															
Asphalt paving		Asphalt paving	99	99			$90,000/ mile			$4,200/ mile			$0.37/ VMT			
Agricultural Production - Crops																
Tilling																
Soil conservation plans	2801000003	See Reference[2]														
Fugitive Dust - Construction, All Processes																
Wind Erosion																
Wind barrier fences		Wind barrier fences	90	90			$10 per running foot of fence			none			$10.70 per running foot of fence			
Fugitive Dust - Paved Roads	2294000000															
Vacuum/sweeping (mitigative control strategy)		Closed loop regenerative air system	80	80	$120,000	$190,000	$155,000				$25,000	$32,000	$28,500			
Treat unpaved access roads (preventive control strategy)		Watering and chemical dust suppression of unpaved access roads	95	95	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a			
Fuel Combustion - Residential Wood	21040080000															
Alternative fuel use: natural gas		Replace wood stove with natural gas fireplace	100	100	$1,400	$3,250	$2,325	-$100	$200	-$100	$37	$547	$292			
		Convert wood fireplace to natural gas fireplace	100	100	$300	$1,050	$675	-$100	$200	-$100	-$74	285	$106			
Other Combustion - Prescribed Burning	2810015000	See Reference[2]														
Waste Disposal & Recycling, Open Burning, Residential	2810015000															
Bans			99	99	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a			

SOURCES: [1]EC/R, 1996.
[2]Pechan, 1997.

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assuming that resurfacing is required for rural roads after 17 years, at a cost of $40,800/mile (Rosenberger, 1995). Capital recovery, based on a 7 percent discount rate and 17 year life, is 0.102. On an annualized basis, this is equivalent to 0.102 x $40,800/mile = $4,160/mile, assuming no additional incremental maintenance costs. Thus, the total annualized cost is $6,750 + $4,160 = $10,910 per mile per year. Assuming 29,200 vehicles per year as typical for rural roads, the annualized cost becomes $10,910 per mile per year/29,200 vehicles per year = $0.37/VMT.

2. Construction Activities

Construction activities are significant sources of PM emissions. In 1990, construction activity emissions comprised approximately 16 percent of total $PM_{2.5}$ emissions and 20 percent of total PM_{10} emissions (Pechan, 1997). Construction activities that produce PM include:

- Land clearing;
- Demolition;
- Blasting;
- Ground excavations;
- Cut and fill operations;
- Vehicle traffic;
- Welding operations; and
- Wind erosion.

Except for vehicle traffic and welding operations, which are based on VMT and tons processed, respectively, construction emissions are estimated based on the total number of acres of construction activity. It is important to note that emission factors are not available for some construction activities and that construction emissions are not available for the individual construction activities listed above (Pechan, 1997).

a. Description of Available Control Options

The following control techniques have been identified as potential construction activity PM control measures:

- Water treatment of disturbed soil;
- Vacuum street sweeping of nearby paved areas;
- Wind barrier fencing;
- Chemical stabilization;
- Controls such as aprons and truck washing for reducing mud/dirt carry-out onto paved roads;
- Early paving of construction roads;
- Speed and/or vehicle weight limits for unpaved roads at construction sites; and
- Prohibiting grading on windy days.

b. Control Options Selected for Analysis

Wind barrier fencing was selected for the present analysis. The other potential measures identified were analyzed in Pechan (1997).

The principle behind wind fencing is to provide an area of reduced wind velocity which provides for both a reduction in the wind erosion potential of the exposed surface, and allows for the gravitational settling of the larger particles already airborne (EPA, 1986). A survey of studies indicated total particulate control efficiencies ranging from 0 to 90 percent (EPA, 1986). This document also states that problems have been noted with the sampling method used in each of these studies, thereby limiting the degree of confidence in the degree of control achievable by wind fences for large open sources. The EPA notes that no data directly applicable to construction/demolition activity wind fences are available (EPA, 1988). Guidance provided by

EPA does not suggest a control efficiency for wind fencing, although it does note that a laboratory wind tunnel study indicated a control efficiency of 60 to 80 percent for materials handling emissions (EPA, 1988). EC/R (1996) reports a 90 percent control efficiency for PM_{10} and $PM_{2.5}$ and rates it as the most effective control for construction activities.

The height of a wind fence is determined by the size and type of source being controlled, level of control needed, and surrounding terrain. For construction applications without elevated sources, a 6 foot high fence of porous polyester material is recommended (Raring, 1999). Capital cost is approximately $10 per running foot. O&M costs are negligible for the life of the fence. Fence life depends on the amount of exposure to ultraviolet (UV) light. Under worst case desert conditions, fabric replacement is necessary after 8 - 10 years. Under average UV conditions, fence life is approximately 20 years. However, for construction applications, the required performance time is usually less than the potential life of the fence, hence assuming a one-year life and 7 percent discount rate, the annualized cost is $10.70 per running foot. It is conceivable that the fence fabric could be reused at another location, however.

3. Fugitive Dust - Paved Roads

Particulate emissions occur whenever vehicles travel over a paved surface, such as a road or parking lot. In general terms, particulate emissions from paved roads originate from the loose material present on the surface. In turn, that surface loading, as it is moved or removed, is continuously replenished by other sources. At industrial sites, surface loading is replenished by spillage of material and trackout from unpaved roads and staging areas. Various field studies have found that public streets and highways, as well as roadways at industrial facilities, can be major sources of the atmospheric particulate matter within an area.

Dust emissions from paved roads have been found to vary with what is termed the "silt loading" present on the road surface as well as the average weight of vehicles traveling the road. The term silt loading refers to the mass of silt-size material (equal to or less than 75 micrometers [μm] in physical diameter) per unit area of the travel surface. The total road surface dust loading is that of loose material that can be collected by broom sweeping and vacuuming of the traveled portion of the paved road.

a. Description of Available Control Options

There are two types of control scenario options: mitigative and preventive. The most practical method used for controlling PM emissions from paved roads using mitigative measures is some type of surface cleaning. Surface cleaning control options include vacuum sweeping, water flushing, and water flushing followed by sweeping. Certain advances in vacuum sweeping have resulted in closed-loop regenerative air systems that are more efficient than most other designs.

Preventive options include road design and controlling practices near the paved road. Specific preventive options are: watering and chemical dust suppression of unpaved access roads leading to paved roads, limiting carryover from unpaved areas to paved roads, and truck covers to minimize deposition of materials being hauled on paved roads. Preventive options would also include methods to reduce VMT, such as through promoting commute options.

b. Control Options Selected for Analysis

The closed-loop regenerative air vacuum system was selected for analysis for the mitigative option. These systems use an air jet generated by a blower and distributed by the floating pickup head to loosen particles in the surface cracks and crevices before drawing them into an internal hopper. A mechanical broom precedes the vacuum section. No water is used. An internal centrifugal dust separator retains and collects the PM for proper disposal. Capital costs vary from $150K to $190K (1999 dollars) for compressed natural gas (CNG) fueled units. Diesel-powered units are approximately $30K less (Harrison, 1999). Unit life is approximately 5 years; however, with thorough maintenance, life can be extended to 8 years. For best performance,

operating speed is limited to 5 miles per hour. Based on a 7 percent discount rate and 8-year life, annualized costs are $25K to $32K. O&M costs are approximately $16 to $18 per curb mile, based on operation with CNG, a thorough maintenance regimen, and a wage scale of approximately $13/hr (Clapper, 1999). The SCAQMD conducted a series of controlled tests for different types of street cleaning designs (Layborn, 1999). Manufacturers voluntarily submitted their equipment for testing. An 80 percent collection efficiency was required to obtain certification. The closed-loop regenerative air vacuum system satisfied this criterion. However, by prior agreement with the manufacturers, the SCAQMD would not divulge the specific collection efficiencies actually obtained (Layborn, 1999).

Watering and chemical dust suppression of unpaved access roads leading to paved roads is selected as the preventive control option. This is reported to have a 95 percent control efficiency (EC/R, 1996). No cost data are available.

4.   Residential Wood Combustion

Residential wood combustion (RWC) emissions include those from traditional masonry fireplaces, freestanding fireplaces (metal zero clearance), wood stoves, and furnaces. In many areas of the country with PM_{10} nonattainment designations, residential wood combustion devices account for a large fraction of PM emissions.

PM emissions from residential wood combustion sources are a result of incomplete combustion. One method of reducing PM emissions is to improve combustion efficiency. This can be accomplished by changing the combustion design or using a catalyst that fosters greater combustion efficiencies at lower temperatures. Other methods used to reduce or eliminate PM emissions from residential stoves include changing the fuel — or characteristics of the fuel consumed.

The NSPS were promulgated in 1988 for wood heaters. These regulations required all new wood heaters to be EPA certified to meet specific PM emission limits in two phases. For Phase I, new wood heaters manufactured on or after July 1988, or sold after July 1990, were required to meet emission limits of 5.5 grams per hour and 8.5 grams per hour for catalytic and noncatalytic wood heaters, respectively. Phase II of the NSPS required all wood heaters manufactured on or after July 1990, or sold on or after July 1992, to meet stricter limits. Phase II emission limits are 4.1 grams per hour and 7.5 grams per hour for catalytic and noncatalytic wood heaters, respectively (EPA, 1989).

a.   Description of Available Control Options

In addition to reductions associated with the NSPS, the following control techniques can be used to further reduce emissions from residential wood combustion:

1. Alternative fuel use: change to natural gas;
2. Ban on existing RWC units;
3. Mandatory curtailment during predicted periods of high PM concentrations;
4. Voluntary curtailment during predicted periods of high PM concentrations;
5. Home weatherization; and
6. Replace existing RWC unit with cleaner-burning RWC unit.

Because these programs are relatively new, ample data does not exist to precisely quantify the cost of controls in terms of dollars per ton of PM reduced (cost effectiveness). Emission reduction and cost estimates for these measures were obtained from EPA guidance documents and augmented with quantitative information from control agencies with experience using these measures.

1. Switching to natural gas requires replacing wood stoves and wood burning fireplaces with gas burning alternatives. Natural gas is the primary fuel alternative to the

combustion of wood as a residential heating fuel. Wood burning fireplaces or wood stoves can be replaced with fireplace inserts that provide heat and reduce PM emissions completely (i.e., 100 percent control of PM emissions). "Gas logs" are also available for installation into a masonry fireplace, but they provide less heat than an insert (EPA, 1989; Vendor Sources, 1999).

2. Banning the use of wood stoves and wood burning fireplaces already installed in homes is an option. While this measure would reduce emissions of all pollutants for RWC units by 100 percent, implementation is unlikely due to a probably negative public reaction. No cost information was found for banning existing RWC units.

3. Mandatory curtailment programs are episodic controls designed to reduce emissions when ambient PM concentrations approach the NAAQS. Several PM nonattainment areas implement mandatory curtailment programs. A large component of the mandatory curtailment program is public education and awareness, another large component is the forecasting system.

4. Voluntary curtailment programs are similar to mandatory curtailment programs except that there are no enforcement penalties involved. The cost for enforcement would be eliminated; however, some tracking of participation in the program would be needed. The EPA guidance document suggests a credit of only a 10 percent reduction for a voluntary program. The Best Available Control Measures (BACM) guidance (EPA, 1992) suggests the use of a mandatory program and notes that many areas which began with a voluntary program have since switched to a mandatory curtailment program. Because of the low reduction potential and since many areas have shown little success with voluntary curtailment, this will not be considered for the cost analysis.

5. Home weatherization seeks to reduce the amount of wood used for home heating by reducing energy consumption required to heat a home. Less heat required to heat a home translates to less wood combusted (and other fuels as well), and lower emissions. Public education, home energy audits, and utility-funded conservation programs are effective means of encouraging weatherization through measures such as dual-pane windows, weatherstripping of doors, and increasing the insulation of homes. No cost information was available for home weatherization programs or the expenses incurred by the public (CAPCOA, 1989).

6. Replacing existing RWC units with cleaner-burning RWC alternatives would result in a range of control efficiencies, depending upon the unit being replaced as well as the new unit. The emission reduction resulting from replacing a pre-Phase I fireplace ranges from 53 to 94 percent, and from replacing a wood stove the reductions range from 45 to 90 percent. Since replacement with natural gas insert or gas log is a more effective option, no cost analyses of these options will be performed.

b.   Control Option Selected for Analysis

The control measure chose for analysis is the conversion of fireplaces and wood stoves to burn natural gas. Capital costs for converting wood burning fireplaces to a gas-burning fireplace insert depend upon several factors, such as the size and type of existing fireplace (masonry or freestanding), the distance between the fireplace and the natural gas or propane tank, and the type of insert chosen.

Wood stoves may also be replaced with free-standing gas fireplaces. The average price for replacement ranges between $1,200 and $2,500 (in 1999 dollars) for the new unit and between $200 and $750 (in 1999 dollars) for installation (depending upon distance to gas line), according to vendors. "Gas logs" range from $250 to $400 (in 1999 dollars) and cost between $50 and $650 (in 1999 dollars) (depending upon distance to gas line) to install (Vendor Sources, 1999). The cost range for the complete system is therefore $1,700 to $4,300. Based on a 7 percent discount factor and 30 year life, the annualized capital cost range is $137 to $347.

Another consideration when determining the cost effectiveness of this measure is the relative operating costs associate with burning wood and natural gas. Operating

costs are dominated by fuel costs, which have been determined to be $172 per household heating with natural gas, and between $0 and $286 per household heating with wood, assuming equivalent heat inputs. These estimates are based on an average wood consumption of 1.3 cords per household per year, 79 ft^3 of solid wood per cord (no air spaces), a wood density of 30.2 lb/ft^3, a wood heating value of 8,613 British thermal units per pound (Btu/lb), and a natural gas heating value of 1,032 Btu/ft^3 (DOE, 1997; EPA, 1997).

The cost for a cord of wood is assumed to be between approximately $130 to $220 based on vendor sources. This cost is likely to vary between urban and rural areas, the season in which the wood is purchased, and the quality of the wood (Vendor Sources, 1995; Vendor Sources, 1999). The cost of natural gas is estimated to be $6.63 per thousand cubic feet (DOE, 1999). Many people may receive firewood free-of-charge, and for these cases, there would be an additional expense associated with changing to a natural gas fired unit. The availability of natural gas may also be a limiting factor for this control strategy in some areas of the country, particularly in more rural areas. Depending upon the price paid for firewood, the net operating costs of converting an RWC unit to burn natural gas could range from a savings of $100 per year (assuming $220/cord firewood) to a cost of $200 per year (assuming firewood is free-of-charge).

Annualized costs were calculated assuming a 7 percent discount rate and 30-year life. The annualized cost range of capital and O&M costs for replacing wood stoves with free-standing natural gas fireplaces is therefore $37 to $547. The annualized cost range of capital and O&M costs for converting wood fireplaces to gas fireplaces (gas logs plus installation) is therefore -$74 to $285. The $74 savings is due to the scenario of saving the cost of firewood.

5. Waste Disposal & Recycling, Open Burning, Residential

Residential open burning material includes yardwaste, garbage, trash, rubbish and other forms of solid waste, including but not limited to wastes resulting form residential, agricultural, commercial, industrial, institutional, trade and construction. Depending on local ordinances, residents are often allowed to open burn yardwaste such as leaves, tree branches or twigs and grass trimmings, but must maintain some sort of minimum of minimum distance from structures and neighbors.

a. Description of Available Control Options

Open burning is regulated by local ordinances which usually include limits and restrictions on pile material to be burned, size and configuration, moisture content, time of day, wind speed and direction. Cooking fires are usually exempt. Residents are usually prohibited from burning garbage, trash, and rubbish. Permits may be required. Regulations serve to manage open burning, but its emissions control effectiveness varies. The most effective control is banning open burning.

b. Control Option Selected for Analysis

Banning open burning is the most effective method of control. However, public acceptance for this approach is questionable, and will likely vary from place to place. Banning will conceivably lead to other disposal alternatives, such as landfills, or as refuse derived fuel (RDF) in a MWC or incinerator. Presumably, effective PM controls on these equipment would result in a significant decrease in PM emissions than would have otherwise occurred from open burning. No cost data are available.

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CHAPTER VI
STATIONARY SOURCE CARBON MONOXIDE CONTROL MEASURES

This chapter presents information on stationary source CO control measures. Carbon monoxide has not received much attention since the number of nonattainment areas is small in comparison to other pollutants such as ozone and PM. CAA controls have focused on motor vehicles, which is the largest emitting sector for CO. Most of the control measures in this chapter date back to before passage of the 1990 Amendments. Research, including contact with the Clean Air Technology Center, did not yield any new information on stationary source CO controls. Table VI-1 presents the control efficiency and cost parameters for stationary source CO emitters. The sections below provide background information on the source categories.

A. CARBON BLACK PRODUCTION

Carbon black (SCC 30100504) is produced by the reaction of a hydrocarbon fuel (usually oil or gas) with a limited supply of combustion air at temperatures of 1320 to 1540°C. Carbon black production is attributed with 15.07 percent of annual CO production. The unburned carbon is used as a reinforcing agent in rubber compounds and as a black pigment in printing inks, surface coatings, paper, and plastics. The two major processes used to manufacture carbon black are the oil furnace process (~90 percent of production) and the thermal process (~10 percent of production). CO emissions tend to be higher for small particle production, corresponding with lower yields (EPA, 1999).

1. Description of Available Control Options

The control option available for this source is thermal incineration with primary heat recovery, with and without the add-on treatment of a CO boiler, incinerator, or flare.

2. Control Option Selected for Analysis

Both thermal incineration and incineration with add-on controls have been considered. Thermal incineration alone has a reported efficiency of 99.5 percent (Pechan, 1988). The use of a flare increases CO combustion efficiency to 99.8 percent (EPA, 1999). Cost equation parameters are given in Table VI-1.

B. IRON AND STEEL PRODUCTION

Iron is produced in blast furnaces by the reduction of iron-bearing materials by use of hot gas. Iron oxides, coke (coal heated in an oxygen-free atmosphere to remove volatile components), and fluxes (limestone, dolomite, or sinter) react to form molten reduced iron, CO, and slag. The production of sinter involves the combustion of fine-sized raw materials into an agglomerated product for use in the blast furnace. The production of 1

Table VI-1
Carbon Monoxide Control Measures for Retrofit Applications
(1985 Dollars)

CO Source	Control Device	Retrofit Capital		Retrofit O&M		Control Eff. (%)	Default Cost/Ton
		a	b	a	b		
Carbon Black	Incin. w/PR	35.0	0.98	4.07	0.94	99.5	3
Carbon Black	Incin. w/PR & CO Boiler	449.0	0.85	-37.20	1.06	99.5	-47
Iron Ore Sinter Plant-Windbox	Incin. w/PR	276.0	0.73	39.60	0.82	90.0	172
Iron Ore Sinter Plant-Windbox	Incin. w/P&SR	206.0	0.76	-0.06	1.32	90.0	-288
Carbon Steel Electric Arc Furnace	Direct Shell Evacuation	534.0	0.65	40.60	0.74	90.0	248
Gray Iron Cupola	Thermal Incin.	4,160.0	0.15	0.99	0.91	90.1	5
Conical Wood Burner	O2 Analyzer	8,060.0	0.00	4,310.00	0.00	50.0	9
Municipal Incinerator	O2 Analyzer	272.0	0.40	138.00	0.42	50.0	102
Basic Oxygen Furnace	Open Hood System	229.0	0.73	-1.51	0.99	95.0	-21
Prebake Aluminum Cells	Incin. w/PR	65.1	1.06	41.20	1.10	99.0	824
Aluminum Anode Baking	Incin. w/PR	2.3	1.09	0.62	1.10	99.0	83
Maleic Anhydride	Incin. w/PR	3,100.0	0.57	57.10	0.93	98.0	50
Maleic Anhydride	Incin. w/P&SR	1,630.00	0.65	2.93	1.22	98.0	45
Coke Oven Charging	Stage Charging	458,000.0	0.04	8,650.00	0.30	99.0	2,613
Cyclohexanol	No Heat Recovery	10,600.0	0.24	68.00	0.64	98.0	38
Cyclohexanol	Incin. w/PR	110,000.0	0.11	334.00	0.49	98.0	43
Ethylene Dichloride	Incin. w/PR	254.0	0.60	1.08	1.00	98.0	--

NOTES: Equations are of the form COST = a*(SIZE)^b. Size varies by source category and is in SCC units.
Incin. w/PR is a Thermal Incinerator with Primary Heat Recovery.
Incin. w/P&SR is a Thermal Incinerator with Primary and Secondary Heat Recovery.

SOURCE: Pechan, 1988.

ton of iron can produce 2.5 to 3.5 tons of blast furnace gas that contains CO and up to 100 lbs of dust. The byproduct gas is collected, cleaned of particulates, and used as a fuel within the steel plant. Iron production is attributed with 12.66 percent of annual CO emissions. Coke manufacturing plants associated with iron and steel production facilities are attributed with 4.23 percent of annual CO emissions.

Gray (cast) iron is an iron-carbon-silicon alloy used for industrial machinery and heavy transportation equipment. Cupolas, electric arc furnaces, and electric induction furnaces are used for production. Only cupolas are a significant source of CO, with 2.08 percent of annual CO emissions attributed to gray iron foundries.

Steel is produced using several methods. The basic oxygen process consists of injecting high-purity oxygen into a furnace containing molten iron from a blast furnace and iron scrap. Carbon and other impurities are removed from the metal. The electric arc furnace is used to produce carbon and alloy steels using electric current to melt and refine scrap materials. The open hearth furnace uses gas burners to melt and refine steel using scrap and molten iron. Steel production is attributed with 12.35 percent of annual CO emissions.

The emission sources included are represented by the following SCCs:

- 30300304
- 30300801
- 30400304
- 30400711

1.   Description of Available Control Options

Blast furnaces for iron production are equipped with capture systems to collect exhaust gas. Two types of hoods are used, either a closed or open hood. A closed hood fits against the furnace mouth and directs all particulates and CO to a wet scrubber gas cleaner. CO is flared at the scrubber outlet stack. An open hood design allows dilution air into the hood, allowing combustion of the CO in the hood system. Windboxes draw combusted air from the sinter production into a gas cleaning device. There, CO emissions can be treated with thermal incineration, with or without primary and secondary heat recovery.

Stage charging during coke oven charging can also lead to reductions in CO emissions. Coal is charged at a reduced rate and suction on the oven is maintained during the charging. CO emissions remain within the oven collection system (Pechan, 1988).

During gray iron production, BACT for CO reduction from cupolas is the use of afterburners or hot top burners (>0.3 second retention time at >1400°F).

During the steelmaking process, the large quantities of CO are controlled by combustion at the mouth of the furnace and vented to gas cleaning devices using either open or closed hoods. For electric arc furnaces, five emission capture systems are used: fourth hold (direct shell) evacuation, side draft hood, combination hood, canopy hood, and furnace enclosures (EPA, 1999).

2.   Control Option Selected for Analysis

The use of thermal incineration with primary heat recovery, and with the addition of secondary heat recovery during the sinter production phase, were considered for analysis. The control efficiency of both controls is 90 percent.

Stage charging can control 99 percent of CO emissions.

For carbon steel electric arc furnaces, a direct shell evaluation system is the control device considered. It controls up to 90 percent of the CO emissions by aspiring air through

an air gap and combusting the CO. An open hood system achieves 90 percent removal by adding air to ensure complete burning of the CO in the hood (Pechan, 1988).

For basic oxygen furnaces, the control measure considered is the open hood system. Available cost parameters are given in Table VI-1.

C.   PULP AND PAPER AND WOOD PRODUCTS

Chemical wood pulping involves the extraction of cellulose from wood by dissolving the lignin that binds cellulose fibers together. Chemical pulping processes are kraft, sulfite, neutral sulfite semichemical (NSSC), and soda. The kraft process accounts for over 80 percent of the chemical pulp in the United States (EPA, 1999). CO emissions from the kraft process include the recovery furnace (where cooking chemicals and heat are recovered after the digesting process) and lime kilns (where lime mud is regenerated into quicklime). The major cause of CO emissions is furnace operation above rated capacity (EPA, 1999). Kraft pulping accounts for 7.72 percent of annual CO emissions. Acid sulfite pulping is accomplished in the same manner as kraft pulping, except that different chemicals are used in the cooking liquor. Acid sulfite pulping is attributed with 0.19 percent of annual CO emissions.

The emission sources included are represented by the following SCCs:

- 30700104
- 30700299

1.   Description of Available Control Options

The CO emissions control considered is the proper operations of furnaces. Data on costs and reductions were not available.

D.   ALUMINUM ORE PRODUCTION

Bauxite ore, a hydrated oxide of aluminum, is refined and electrolytically reduced to form elemental aluminum. The CO produced is treated as carbon dioxide (CO_2) because it is assumed that it will eventually be oxidized after being emitted (EPA, 1999). CO emissions from aluminum ore production account for 6.36 percent of annual emissions. The emissions are represented by SCC 30300199. No available controls were identified.

E.   BITUMINOUS/SUBBITUMINOUS COAL COMBUSTION

Coal rank increases as the amount of fixed carbon increases and the amount of volatile matter and moisture decreases. Bituminous coals are the largest group and are characterized as having a lower fixed carbon and higher volatile matter than anthracite. Subbituminous coals have higher moisture and volatile matter and lower sulfur content than bituminous coals. Emissions depend on the rank and composition of the fuel, the type and size of the boiler, firing conditions, load, type of control technologies, and the level of equipment maintenance.

The emission sources included are represented by the following SCCs:

- 10100212
- 10200204
- 10300205
- 39000201

1.   Description of Available Control Options

The rate of CO emissions depends on the fuel oxidation efficiency of the source. If the combustion process is not controlled or a unit not properly operated or maintained, CO emissions may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces

typically emit more CO than larger combustors because they have less high-temperature residence time, and therefore, less time than larger combustors to achieve complete combustion. If improperly designed or implemented, NO_x reduction equipment can increase CO emissions (EPA, 1999). No controls were identified for inclusion in ControlNET.

F.   WOOD/BARK WASTE COMBUSTION

Wood and bark waste combustion is generally confined to industries where it is available as a byproduct (e.g., pulp mills, lumber, furniture, or plywood industries). CO emissions are increased when proper drying is not achieved or when secondary combustion is not complete thereby lowering the combustion temperature. Nearly all of the fuel carbon (99 percent) in wood waste is converted to CO_2 during the combustion process (EPA, 1999). However, industrial wood/bark waste combustion is attributed with 3.61 percent of annual CO emission and commercial wood/bark waste combustion is attributed with an additional 1.98 percent of annual CO emission.

The emission sources included are represented by the following SCCs:

- 10200905
- 10300902

1.   Description of Available Control Options

The use of O_2 analyzers can reduce CO emissions by optimizing combustion.

2.   Control Option Selected for Analysis

The efficiency of O_2 analyzers is a 50 percent reduction in CO emissions (Pechan, 1988). Cost parameters are given in Table VI-1.

G.   NATURAL GAS COMBUSTION

Natural gas combustion is used mainly for industrial process steam and heat production; for commercial space heating; and for electric power generation. The rate of CO emissions from boilers depends on the efficiency of natural gas combustion (EPA, 1999). Internal combustion boilers using natural gas for industrial sources are attributed with 2.98 percent of annual CO emission and external combustion boilers are attributed with an additional 1.26 percent. Electric generation using natural gas is attributed with 1.25 percent (external combustion boilers) and 0.69 percent (internal combustion boilers) of annual CO emission.

The emission sources included are represented by the following SCCs:

- 20200202
- 10200602
- 10100604
- 20100202

1.   Description of Available Control Options

In a properly tuned boiler, nearly all of the fuel carbon (99 percent) in natural gas is converted to CO_2 during the combustion process. The addition of NO_x control systems (e.g., low NO_x burners and flue gas recirculation) may reduce combustion efficiency, resulting in higher CO emissions relative to uncontrolled boilers (EPA, 1999). Some induced flue gas recirculation systems can lower NO_x without increasing CO levels (Cleaver Brooks, 1999). No control options were identified for inclusion in ControlNET.

H.   CHARCOAL MANUFACTURING

Charcoal is the solid carbon residue following the carbonization or destructive distillation of carbonaceous raw materials, most often medium to dense hardwoods. Manufacturing is accomplished in batch or continuous kilns. Emission levels are variable from plant to plant depending on the raw materials and the kiln type. Most emissions are from the kiln exhaust (EPA, 1999). Charcoal manufacturing is attributed with 0.64 percent of annual CO emissions. The SCC for emissions from charcoal manufacturing is 30100699.

1. Description of Available Control Options

Continuous production of charcoal is more amenable to emission control than batch production because emission composition and flow rate are relatively constant. Emissions control is usually achieved with afterburners. Batch-type kilns typically do not have emission control devices, but some may use afterburners.

2. Control Option Selected for Analysis

Afterburners for continuous multiple hearth charcoal kilns are the control option considered. Reductions achieved by this method are estimated to be at least 80 percent. Cost parameters were not identified.

I. MINERAL WOOL MANUFACTURING

Mineral wool is manufactured for use in insulation and other fibrous building materials that are used for structural strength or fire resistance. Mineral wool is a fibrous glassy substance made from minerals, e.g., natural rock and slags from iron, copper, lead, and phosphate production (EPA, 1999). Mineral wool production is attributed with 0.45 percent of annual CO production. The SCC for emissions from mineral wool manufacturing is 30501701.

1. Description of Available Control Options

CO emissions occur primarily from coke combustion in the furnace where most control measures are directed toward PM control. Afterburners have been used to control CO emissions. A gas-fired melting option, in place of the coke-fired cupola, has been developed for mineral wool production. Efficiency and cost parameters have not been identified.

2. Control Option Selected for Analysis

The control option considered is the gas-fired production unit. Compared to a coke-fired cupola facility operating with a pollution abating afterburner producing fiber at approximately $71/ton, the gas fired unit operating at a melting efficiency of 4.5 million British thermal units (MMBtu) per ton is about $41/ton of mineral fiber (based on a natural gas cost of $5/Mcf) (Ridderbusch, 1990). This process eliminates CO emission as well as offering other production benefits.

J. FLARES

Flares are incendiary devices which ensure safe combustion of waste gases when the blowdown volume exceeds the storage capacity of the recovery subsystem. Blowdown systems are designed to provide safe containment or release of liquids and gases that must be vented. It is the last opportunity to treat blowdown gases before they are released to the atmosphere. Completeness of combustion in flares is determined by flame temperature, residence time in the combustion zone, turbulent mixing of the components to complete the oxidation process, and available oxygen (SCAQMD, 1996). Flares are attributed with 0.51 percent of annual CO emissions. The emission sources are included under SCC 30600903.

1.   Description of Available Control Options

NSPS for flares that operate continuously or for emergency purposes is a 98 percent combustion efficiency. The BACT guidelines for the South Coast list the following controls as "achieved in practice," or "contained in EPA approved SIP for refinery flares": ground level, shrouded and steam assisted (SCAQMD, 1996).

K.   REFERENCES

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CHAPTER VII
STATIONARY SOURCE AMMONIA CONTROLS

Pechan-Avanti focused efforts on developing cost modeling parameters for livestock emissions. This source sector contributes 55 percent of the 1996 update to Trends emissions (Roe and Strait, 1998). Within the overall livestock emissions sector, cattle operations contribute most of the NH$_3$ emissions. These emissions are classified under SCC 2805001000 (beef cattle feedlots) and 2805010000 (dairies). Hog operations are classified under SCC 2805015000 and poultry operations are under 2805005000.

A. DESCRIPTION OF AVAILABLE CONTROL OPTIONS

Control options that have been demonstrated for livestock include diet optimization, chemical additives (to animal wastes), and various add-on controls (i.e., capture of ammonia that has been release to the air). With diet optimization, the goal is to reduce unnecessary nitrogen intake of the animal (i.e., protein), such that the amount of nitrogen lost to urine and feces is reduced. Typically, the protein content of the feed is reduced and essential amino acids are supplemented.

Chemical additives include urease inhibitors which prevent the urease enzyme (produced from bacteria in the manure) from hydrolyzing urea to ammonia. Another chemical additive, alum (aluminum sulfate), has been used to stabilize poultry litter to reduce ammonia emissions. Acid-forming compounds, such as alum, keep the pH of the poultry litter below 7, which inhibits ammonia volatilization (ammonia volatilization is significant at pH greater than 7) (Moore et al., 1995).

Add-on controls include biofilters and wet scrubbers placed on the building exhaust of confined animal operations. Also included are biocovers which are some type of cover material placed over a storage lagoon. Both of these control types involve adsorption of ammonia and possible subsequent oxidation (chemical or biological). Some additional, although less studied control alternatives are mentioned in the individual livestock category sections below.

B. CONTROL OPTIONS SELECTED FOR ANALYSIS

Livestock ammonia controls and cost estimates are listed in Table VII-1. Descriptions of the control options selected for analysis are given below for each of the livestock categories (cattle, poultry, and hogs).

1. Cattle

Ammonia emissions from cattle operations in the NPI are estimated using a composited emission factor of 22.9 kilograms (kg) NH$_3$ per head per year (kg/head-yr). The composite emission factor accounts for (1) the relative proportion of cattle and calves; and (2) the sum of emissions occurring during confinement (stable), storage of the waste

Table VII-1
Livestock Ammonia Controls and Cost Estimates

NH$_3$ Group	NH$_3$ Group Name	Control Strategy	Control Measure	SCC	Control Efficiency (%)	Annualized Costs[1] (Typical)	Cost Effectiveness[1] (Typical)
01	Cattle	1	Chemical Additives[2]	2805020000	50	$2.85/head-yr	$228/ton NH$_3$
02	Poultry	1	Chemical Additives[3]	2805030000	75	$0.15/head-yr	$1,014/ton NH$_3$
03	Hogs	1	Chemical Additives[2]	2805025000	50	$0.37/head-yr	$73/ton NH$_3$

NOTES:

[1] Costs are in 1999 $.
[2] Urease inhibitor N-(n-butyl) thiophosphoric triamide.
[3] Alum treatment.

(as solid or slurry), spreading of the waste (in crop fields), and grazing. Confined operations refer to cattle confinement (in dairy barns or feedlots), waste storage, and subsequent waste spreading. Unconfined operations refer to grazing. The portion of the emission factor associated with confined operations (~20 kg/head-yr) is nearly an order of magnitude higher than the emission factor for unconfined operations (~3 kg/head-yr).

Assessment of control measures applicable to ammonia emissions for cattle operations is still in the early stages (MPCA, 1999). Work conducted to date is often done to assess control of odors and/or emissions of other substances (hydrogen sulfide). This work has focused on control of emissions from confined operations. Given that confined operations contribute most of the emissions (and that control of emissions from unconfined operations is probably not feasible), research was performed on cost modeling data and methods for confined operations only.

Potential control measures cited by MPCA (1999) include biological and chemical additives (to eliminate or reduce NH_3/odor formation), biofilters and biocovers (to adsorb and oxidize NH_3), electrical conductivity and non-thermal plasma treatment (to treat collected gases), aeration (of stored slurry), anaerobic digestion (of stored slurry followed by energy recovery from the biogas), and crust formation (on earthen manure storage structures). Other than the use of chemical controls, specifically urease inhibitors, sufficient information was not available to develop cost modeling data. Urease inhibitors act by blocking urea hydrolysis (which produces ammonia) by the urease enzyme (produced by bacteria in the cattle waste).

Varel et al. (1999) reported on the ability of two types of urease inhibitors in reducing ammonia losses from cattle feedlot waste (through measurement of nitrogen conservation). These chemicals need to be applied (sprayed) over the feedlots on a routine basis. Pechan-Avanti contacted the manufacturer of the more effective inhibitor, N-(n-butyl) thiophosphoric triamide (NBPT; trade name Conserve-N®). According to the manufacturer, the control effectiveness at cattle feedlots is 50 percent and the cost per head-day is $0.0062 ($2.26/head-yr; Axe, 1999). The manufacturer also reports that field tests are ongoing at dairies and that the product should perform the same (50 percent control), but cost slightly more $0.0094/head-day ($3.43/head-yr; Axe, 1999). It was not clear why the costs would be higher at dairies.

As noted above, the inventory currently does not differentiate between confined and unconfined operations (Pechan-Avanti has developed methods to do this; however, they have yet to be incorporated into EPA's inventories). Emissions need to be broken out into at least two, if not three, source categories (e.g., feedlots, dairies, unconfined/grazing). Until this is done, it is assumed that cattle in confined and unconfined operations are the same throughout the United States. This assumption will result in reasonable estimates of cost and reductions in areas with high proportions of confined operations (e.g., beef producing States), since the emission estimates are driven by confined operations (as described above). However, in areas where the proportion of confined and unconfined operations are more even, there will be overestimates of cost and reductions (since the emissions have been overestimated). For areas where cattle are primarily grazing, the controls should not be applied (controls are not viable in these situations).

Pechan-Avanti developed county-level population fractions of confined cattle (dairy and beef) and cattle in unconfined operations (i.e., grazing) from the 1997 Census of Agriculture (COA). Table VII-2 provides a sample of the data from this assessment. COA data for "cattle fattened on grain and concentrates" was used as a surrogate for cattle at feedlots. The COA also contains data for milk cows at the county-level. These data were used along with the total cattle and calves inventory to obtain the fractions shown in Table VII-2. In the United States, about 9 percent of the population is dairy, 28 percent feedlot cattle, and the remaining 63 percent are presumed to be grazing cattle. The data in the table also show the variability of these data at the State and county levels. In Nebraska, a large beef producing State, the majority of cattle are shown to be in feedlots. In a sampling of California counties, El Dorado county is shown to have little in the way of confined operations, while the two other counties have significant dairy operations.

Table VII-2

Example Fractions of Confined and Unconfined Cattle Operations at Specified Geographic Locations

	Confined Operations		
Area	Dairy	Feedlot	Unconfined Operations
United States	0.09	0.28	0.63
Nebraska	0.01	0.72	0.27
Wisconsin	0.39	0.07	0.54
El Dorado Co., CA	0.002	0.006	0.99
Riverside Co., CA	0.55	0.003	0.44
San Joaquin Co., CA	0.39	0.03	0.58

For some counties, the totals for feedlots were higher than the county totals. These differences were usually slight and probably due to some survey anomaly. In these instances, it is assumed that all cattle in that county are in confined operations. For counties without complete data (e.g., due to confidentiality issues), the State-level population fractions should be used. In order to derive a county-level control factor, the 50 percent control efficiency multiplied by a county-level penetration factor. This penetration factor is derived by multiplying 0.87 (20/23; which, as mentioned above, accounts for the portion of the emission factor for confined operations) by the county-specific confined operations fraction (dairy plus feedlot fractions).

To estimate costs, an average per head cost between dairy cattle and feedlot cattle would be \$2.85/head-yr (from the values given above). The emission factor for cattle is about 23 kg/head-yr (0.025 ton/head-yr). A 50 percent control efficiency yields 0.0125 ton/head-yr reduced). Hence, the cost factor would be \$2.85/0.0125 ton or \$228/ton of NH_3 reduced.

2.   Poultry

The most thoroughly studied and documented ammonia control option for poultry operations is chemical addition of alum to poultry litter. Most of this work has been conducted on broiler raising operations; however, the control technique should be applicable to layer (egg) operations, as well (although the application of alum would be performed somewhat differently) (Moore, 1999). As information was only available for broiler operations, it is assumed that the emission reductions and cost effectiveness model inputs are the same. Axe (1999) also reports that the same urease inhibitor product described above for cattle (Conserve-N[®]) has applicability for poultry; however, sufficient information to develop cost modeling inputs was not available in time for this study.

The control effectiveness for alum treatment is estimated to be 75 to 80 percent (Moore, 1999). The control effectiveness is highest during the early part of the growing cycle (i.e., >95 percent), when the young chickens are most susceptible to health problems from high ammonia levels. The control effectiveness drops off during the grow-out (about two months). Alum is then reapplied to the litter before the next grow-out begins (typically, there are 5 or 6 grow-outs per year). A 75 percent control parameter is selected for modeling purposes. There is assumed to be 100 percent penetration.

Treatment costs are estimated to be about \$0.025/head (Moore, 1999). These costs do not factor in some benefits to the grower (e.g., reduced heating/ventilation costs due to lower ammonia levels; higher value for fertilizer due to higher nitrogen levels). Assuming six grow-outs per year, the costs would be \$0.15/head-yr. The emission factor used for all poultry is 0.394 lb/head-yr (1.97×10^{-4} ton/head-yr). Assuming a 75 percent control efficiency for alum treatment, the emission reduction would be 1.48×10^{-4} ton/head-yr reduced. Hence, the cost parameter would be \$0.15/1.48E-04 ton reduced or \$1,014/ton NH_3 reduced.

3.   Hogs

Cost information for control of hog operations using Conserve-N® were given by Axe (1999) to be $0.0010/head-day or ($0.37/head-yr). The same 50 percent control efficiency given above for cattle and poultry is assumed for hogs (Axe, 1999). The emission factor for hogs is 20.3 lb/head-yr. With the 50 percent control efficiency, this equates to 10.15 lb/head-yr reduced (5.08×10^{-3} ton/head-yr reduced). Therefore, the cost parameter would be $0.37/5.08E-3 ton or $73/ton NH_3 reduced. There is assumed to be 100 percent penetration; however, the modeling parameters are probably most applicable to large hog farming operations. Hence, it may be more reasonable to apply the control in counties with large hog raising operations (i.e., using COA data).

C.   REFERENCES

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CHAPTER VIII
UTILITY SOURCE

This chapter evaluates potential NO_x, PM, and SO_2 utility source control measures. Table VIII-1 presents a complete list of control measures incorporated into ControlNET, differentiating between measures that are documented in this report and measures documented in previous reports. This chapter identifies the newly developed control measures, as well as revisions to measures developed in previous analyses. The general impetus for these revisions is the availability of new information.

A.   EGU SOURCE NO_x CONTROL MEASURES

Control cost equations used for estimating the costs of applying selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), and natural gas reburn (NGR) controls were developed for electric utility boilers from EPA's IPM (EPA, 1998). The cost equations used in this analysis are based on cost equations developed to scale costs to smaller or larger boilers than the model plant. Model plants were considered to have boiler design capacities of 200 MW, except coal-burning plants applying SNCR for which model plants had capacities of 100 MW.

Several simplifying assumptions were made in developing the costing parameters used for this analysis. A high NO_x rate ($\geq$ 0.5 pounds per MMBtu) and a capacity utilization factor of 65 percent were assumed for the utility boilers, as well as a 7-percent discount rate and 20-year lifetime of the SCR controls. A control efficiency of 80 percent was assumed for SCR controls on both coal and oil or gas-fired utility boilers. The costing information for applying SCR controls to utility boilers is listed in Table VIII-1.

B.   EGU SOURCE SO_2 CONTROL MEASURES

1.   FGD Scrubbers

Control cost equations used for estimating the costs of applying FGD scrubbers were developed for electric utility boilers. The cost equations used in this analysis are based on cost equations developed to scale costs to smaller or larger boilers than the model plant. Model plants were considered to have boiler design capacities of 500 MW. Several simplifying assumptions were made in developing the costing parameters used for this analysis. A capacity utilization factor of 65 percent were assumed, as well as a 7-percent discount rate and 15-year lifetime of the SCR controls. A control efficiency of 90 percent was assumed for scrubbers on all utility boiler fuel types.

Table VIII-1
NO$_x$ Control Costs for Utility Boilers

Fuel Type	Total Capital Cost ($/kilowatt)	Fixed O&M Cost ($/kilowatt/year)	Variable O&M Cost (millions/kilowatt hour)	% Removal
SNCR[1] (Coal - Cyclone)	8.0	0.12	1.05	35
SNCR[2] (Coal - All others)	15.8	0.24	0.73	35
SNCR[3] (Oil/Gas)	7.8	0.12	0.37	50
NGR[4] (Coal)	26.9	0.41		50
NGR[4] (Oil/Gas)	16.4	0.25	0.02	50
SCR[4] (Coal)	59.6	5.30	0.33	80
SCR[4] (Oil/Gas)	23.3	0.72	0.08	80

NOTES:
[1]Scaling factor for SNCR (Coal - Cyclone) is $(100/MW)^{0.577}$.
[2]Scaling factor for SNCR (Coal - All others) is $(100/MW)^{0.681}$.
[3]Scaling factor for SNCR (Oil/Gas) is $(200/MW)^{0.577}$.
[4]Scaling factors for NGR and SCR (both Coal and Oil/Gas) are $(200/MW)^{0.35}$.

Costing equations for 2 percent, 3 percent and 4 percent fuel sulfur content levels were developed for this model. The costing information for applying wet scrubber controls to utility boilers are listed in Table VIII-2.

Table VIII-2
SO₂ Scrubber Control Costs for Utility Boilers[1]

Fuel Type	Total Capital Cost ($/kilowatt)	Fixed O&M Cost ($/kilowatt/year)	Variable O&M Cost (millions/kilowatt hour)
Medium Sulfur (2% S)	149	5.4	0.83
High Sulfur (3% S)	166	6.0	6.3
Medium Sulfur (2% S)	174	6.3	1.8

NOTE: [1]Scaling factor for Scrubber is (500/MW)^0.6.

C. EGU SOURCE PM CONTROL MEASURES

The costs for fabric filters used to control PM emissions in this analysis were developed for previous analyses. The costing information listed in Tables VIII-3, VIII-4, and VIII-5 can also be found in Pechan-Avanti's *Additional Control Measure Evaluation for the Integrated Implementation of the Ozone and Particulate Matter National Ambient Air Quality Standards, and Regional Haze Program* (Pechan, 1997) and, more specifically, Pechan-Avanti's *Regional Particulate Strategies - Draft Report* (Pechan, 1995).

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Table VIII-3
Equations for Estimating Capital Costs for Fabric Filters on Utility Boilers Fired with Oil or Coal*

Fabric Filter Type	Boiler Fuel Type	Equation**	R2 Value
Total Purchased Equipment Cost Equations			
Shaker	Oil/Coal	5.7019x + 77489	1.00
Reverse-Air	Oil/Coal	5.7993x + 69721	1.00
Pulse-Jet	Oil	1.9634x + 59341	1.00
Pulse-Jet	Coal	2.4967 + 59491	1.00

NOTES: *Applies to units fired with any type of oil or coal.
**The variable "x" is the actual airflow rate into the fabric filter (actual cubic feet per minute).
Multiply purchased equipment costs by 2.17 to estimate total installed capital costs.
Multiply total installed capital costs by 1.4 to estimate retrofit costs.

Table VIII-4
Equations for Estimating Annual Operating and Maintenance Costs for Fabric Filters on Utility Boilers
Fired With Oil*

Fabric Filter Type	Electricity		Dust Disposal		Bag Replacement, $		Compressed Air, $	
	Equation**	R2 Value	Equation**	R2 Value	Equation**	R2 Value	Equation**	R2 Value
Shaker	0.1876x - 19.576	1.00	0.0007x + 0.1895	1.00	0.2411x + 1224.2	1.00	Not Applicable	
Reverse-Air	0.2809x + 542.09	1.00	0.0007x + 0.1895	1.00	0.2866x + 1486.8	1.00	Not Applicable	
Pulse-Jet	0.1962x - 21.837	1.00	0.0007x + 0.1895	1.00	0.1152x + 1.7916	1.00	0.1659x - 0.6381	1.00

NOTES: *Applies to any type of oil.
                     **The variable "x" is the actual airflow rate into the fabric filter (actual cubic feet per minute).

Table VIII-5
Equations for Estimating Annual Operating and Maintenance Costs for Fabric Filters on Utility Boilers Fired With Coal*

Fabric Filter Type	Electricity		Dust Disposal		Bag Replacement, $		Compressed Air, $	
	Equation**	R2 Value	Equation**	R2 Value	Equation**	R2 Value	Equation**	R2 Value
Shaker	0.1941x - 15.956	1.00	0.7406x + 1.1461	1.00	0.2497x + 1220.7	1.00	Not Applicable	
Reverse-Air	0.2869x + 562.52	1.00	0.7406x + 1.1461	1.00	0.2952x + 1488.7	1.00	Not Applicable	
Pulse-Jet	0.2126x - 1.8948	1.00	0.7406x + 1.1461	1.00	0.1465x + 1.1497	1.00	0.1659x - 0.6381	1.00

NOTES: *Applies to any type of coal.
**The variable "x" is the actual airflow rate into the fabric filter (actual cubic feet per minute).

CHAPTER IX
HIGHWAY VEHICLES

This chapter analyzes control measures, their cost, and cost effectiveness for highway vehicle mobile sources. For the purposes of this report only additional control measures, above and beyond the existing (baseline) CAA measures, are analyzed. The control measures examined in this chapter fall into the following four source categories:

- Vehicle Technology;
- In Use Vehicles;
- Fuel Options; and
- Transportation System Modifications.

A.   VEHICLE TECHNOLOGY

1.   Tier 2 Emission Standards

a.   Description

EPA has proposed Tier 2 motor vehicle emission standards and gasoline sulfur control requirements. For cars and light trucks, the proposed program would apply a single average exhaust emission standard that would cover both passenger cars and all light trucks. This program builds on the recent technology improvements resulting from the successful National Low Emission Vehicle program and would also improve the performance of these vehicles through low sulfur gasoline (EPA, 1999).

b.   Emission Reduction Estimate

The combined benefit of Tier 2 emission standards and associated fuel sulfur limits in 2007 is 9.9 percent for VOC exhaust and 25.5 percent for NO_x. These benefits apply to light-duty gasoline vehicles (LDGVs) and light-duty gasoline trucks (LDGTs) (EPA, 1999). These estimates are from the EPA Tier 2 spreadsheet model for the 47-State example.

c.   Cost and Cost Effectiveness

i.   Cost per Ton of VOC and NO_x Reduction

The discounted lifetime nonmethane hydrocarbon plus NO_x cost effectiveness for the first five years of the program is $2,134 per ton. For year six and beyond, the cost effectiveness is $1,748 per nonmethane hydrocarbon plus NO_x ton reduced (EPA, 1999).

ii.   Total Cost

The costs of the Tier 2 proposal can be divided into vehicle costs for technology improvements to meet the more stringent emission standards, and increased fuel costs to meet the gasoline sulfur restrictions. Table IX-1 provides EPA's estimates of the per vehicle increase in purchase price for light-duty vehicles (LDVs) and light-duty trucks (LDTs). The near-

term cost estimates are for the first years that vehicles meeting the standards are sold, prior to cost reduction resulting from lower production costs and retirement of fixed costs (EPA, 1999).

Table IX-1
Estimated Purchase Price Increases Due to Proposed Tier 2 Standards

Standards	LDV	LDT1	LDT2	LDT3	LDT4

Tailpipe Standards
  Near term (year 1)
  Long term (year 6 and beyond)
	$76
	46
		$69
		43
			$132
			99
				$270
				214
					$266
					209

Evaporative Standard	4	4	4	4	4

The EPA-estimated per gallon gasoline cost increases for the years 2004, 2010, and 2015 (EPA, 1999) are as follows.

Estimated Per Gallon Cost for Desulfurizing Gasoline in Future Years

Year	Cost (cents per gallon)
2004	1.7
2010	1.5
2015	1.4

B.   IN-USE VEHICLES

1.   Inspection and Maintenance

a.   Description

Inspection and Maintenance (I/M) is a way to check whether the emission control system on a vehicle is working properly. The measure is designed to ensure that vehicles stay clean while in use. Periodic checks will result in required repairs for those vehicles that fail the test. In addition, tampering with emission control devices will be reduced (EPA, 1993).

On November 5, 1992, EPA established performance standards and other requirements for basic and enhanced vehicle I/M programs. In this rule, enhanced I/M programs were required in serious, severe, or extreme ozone nonattainment areas with urbanized populations of 200,000 or more; and all metropolitan statistical areas with a population of 100,000 or more in the Northeast OTR. These requirements have changed somewhat since the November 1992 rule was released, and implementation of enhanced I/M programs has been much slower than originally planned. The high-tech emission test that EPA originally proposed that areas use in an enhanced I/M program is commonly known as an IM240 test. This test involves running each vehicle through a 240 second test cycle on a dynamometer under load. Enhanced I/M programs were also to include pressure and purge tests of the evaporative emission control systems to ensure that there are no leaks and that the evaporative canister operates properly.

In practice, many areas have implemented decentralized I/M programs that use acceleration simulation mode equipment because this equipment costs much less than the IM240 system. The cost analysis that follows has estimates for three generic I/M program types: basic I/M, low enhanced I/M, and high enhanced I/M, to represent some of the variety of programs that are observed in practice.

b. Emission Reduction Estimates

Emission reductions depend upon the I/M program utilized. Reductions can range from 5 percent to 30 percent for vehicle-related hydrocarbon and CO. In addition, the program can also lead to reductions in NO_x emissions of up to 10 percent (EPA, 1993).

c. Cost and Cost Effectiveness

i. Basic I/M

Costs for basic I/M are based on the RIA for enhanced I/M (EPA, 1992c). The total-per-vehicle cost is based on the inspection fee, average repair cost, and the fuel economy benefit. The average-per-vehicle cost is estimated to be $5.70. This is applied to LDGVs, LDGT1s, and LDGT2s in areas where basic I/M is required. If a basic I/M program is required and a county already has a current I/M program, then no additional cost is attributed to that area. Basic I/M costs are divided evenly among VOC, NO_x, and CO (Pechan, 1998).

ii. Low Enhanced I/M

Costs for low enhanced I/M and OTR low enhanced I/M have not been well defined. Therefore, its cost is considered equivalent to those of basic I/M. The average cost per vehicle for this program is estimated to be $5.70 per vehicle. This per-vehicle cost applies to all registered LDGV, LDGT1, and LDGT2 (Pechan, 1998).

iii. Enhanced I/M

Estimates of enhanced I/M costs are subject to change as States make decisions about their program designs. I/M program costs may be higher or lower according to program designs selected by States. Enhanced I/M costs were also taken from the regulatory support document. The estimated per-vehicle cost is $15.70. This figure is based on a test fee of $18, an average repair cost of $14.20 per vehicle, and an average fuel economy benefit of $16.50 per vehicle. Annual costs can be estimated by applying the per vehicle costs to the projected vehicle registrations for an area (Pechan, 1998).

2. Heavy Duty Diesel Vehicle Roadside Testing

a. Description

In practice, roadside testing of heavy-duty diesel vehicles (HDDVs) is performed by stopping the vehicle or running it at a controlled speed past a checkpoint. An opacity meter measures the transmittal of light through the exhaust plume, thereby measuring the amount of particulates in the plume. This is an indirect and rough measure of the amount of NO_x and particulates in the plume. Some States are conducting these tests on a random and/or targeted basis, largely at truck weigh stations, safety pullovers and similar examinations. States appear to be conducting this activity to reduce the number of severity of smoking vehicles, or those emitting high amounts of particulates from poorly performing engines, in part to reduce particulates and in part to provide a measure of equity with LDGV emission tests.

Currently, no EPA program provides emission credits for HDDV testing: the linkage between exhaust opacity and NO_x is not yet certain. Several States have initiated programs despite lack of available emission credits. AZ, CA, and CO use opacity tests and cite violators, providing time period to repair and be re-tested without fine. NJ instituted self inspection, periodic inspection, and roadside inspection programs which are currently under revision for simplicity and inspector productivity reasons. In June 1999, the Ozone Transport Commission (OTC) States signed a resolution regarding interstate cooperation on the testing of

heavy-duty diesel-fueled trucks and buses. Through this resolution, the OTC endorsed the testing of heavy-duty on-road diesel trucks and buses (OTC, 1999).

b.　　　　　Emission Reduction Estimate

Neither MOBILE5 nor MOBILE6 will include the means to estimate heavy-duty vehicle (HDV) inspection program benefits. The State of California has implemented the "Heavy-Duty Vehicle Inspection Program" (HDVIP) in November 1991 and developed the "Periodic Smoke Inspection Program" (PSIP) in 1993. The emissions of ROG (Reactive Organic Gases), NO_x, and particulates will be reduced by the HDVIP and PSIP programs.

The HDVIP and PSIP Emission Reductions (percent) are estimated as follows for two calendar years (CARB, 1997):

		ROG	NO_x
PM			
1999	13%	2.8%	17.9%
2010	13.4	3.5	
18.0			

c.　　　　　Cost and Cost Effectiveness

The analysis that follows is based upon recent cost estimates for California (CARB, 1997):

California estimated annual HDDV inspection program costs:

Annual Labor Cost
= 　　　　$1,642,385

Annual Smokemeter Capital Cost
= 　$6,817,787

Annual Cost of Inspections
= 　$14,027,474

Total Fleet Annual Administrative Cost 　　　　=　　　　　　　　$22,487,646

Total Cost to Vehicle Owners:

Annual Total Repair Cost
=　　　　$16,208,686

Annual Increased Maintenance Cost 　　　　　　　　　　　　　=
$2,942,920

Annual Lost Opportunity Cost of Time 　　　　　　　　　　　　=
$607,135

Annual Savings Cost of Fuel
= 　　-$24,983,117

Total Annual Cost to Vehicle Owners 　　　　　　　　　　　　=
-$5,238,756

Total Program Cost for 2010 　　=　　　　　Total Fleet Adm. Cost + Total Cost Vehicle Owners

　　　　　　　　　　　　　　　　　=　　　　　　　　$22,487,646
+ (-$5,238,756)

　　　　　　　　　　　　　　　　　=　　　　　　　　$17,248,890

Total Program Cost per Day 　　　$17,248,890 / 365 days = $47,257 per day

Using the emission reduction estimates for 2010 the cost effectiveness values are:

$$\text{Cost per Ton } (NO_x) = \$47,257 \ / \ 14.03 \text{ tpd} = \$3,368 \ / \text{ ton}$$

$$\text{Cost per Ton } (NO_x + ROG) = \$47,257 \ / \ 19.33 \text{ tpd} = \$2,445 \ / \text{ ton}$$

$$\text{Total Cost per Ton } (NO_x + ROG + PM) = \$47,257 \ / \ 22.53 \text{ tpd} = \$2,098 \ / \text{ ton}$$

3. Remote Sensing

a. Description

Remote sensing instruments monitor individual vehicle pollutant emissions by referencing a measurement of the pollutant's concentration to the carbon dioxide concentration in the vehicle exhaust. These measurements are made simultaneously and immediately behind the moving vehicle and, thus have the potential to provide the best possible information on actual in-use vehicle emission profiles. Remote sensing can also be used as a way to identify high emitters to be directed to I/M facilities for testing. Another option for remote sensing is to use it for clean screening in I/M programs. EPA has recently completed a draft guidance document on the use of clean screening in I/M programs. Clean screening is designed to exempt certain cars from the I/M requirement, on the strength of other evidence of the high probability that they are clean enough to pass anyway. Based on a preliminary assessment of data currently available, EPA believes that it is possible to excuse up to one-third of cars from inspection each year, with only a 5 to 10 percent loss in emission reductions (EPA, 1998).

The Arizona Department of Environmental Quality has had a legislatively mandated gross emitter remote sensing program since 1995. Cars and light trucks that have two remote sensing readings within a time period that are above set CO and HC values (which differ by model year), are mailed a notice requiring them to have an emission test within 30 days. Cars that are not retested have their registration suspended. The Phoenix program operates in Maricopa County, which has a centralized, IM240 dynamometer-based emissions inspection program. There are six remote sensing units that gather measurements 4 days per week, 7 hours per day. This results in 150,000 records per month being submitted to the State Motor Vehicle Bureau. Historically, this has resulted in 9,000 vehicle re-tests per year. This has been with a paired van/instrument deployment. A recent change with a single van set-up has reduced the number of re-tests to about 3,000 per year. Annual program cost is $914 thousand (Grubbe, 1999).

b. Emission Reduction Estimates

An analysis of clean screening in one State indicates that by using remote sensing cutpoints that excuse 37 percent of remotely tested vehicles with a fleet coverage of 80 percent, the loss in tailpipe HC benefit is about 4 percent and the loss in overall HC benefit is 5 to 8 percent. By using remote sensing clean screening to measure NO_x with a tight NO_x cutpoint, NO_x benefit losses can be limited to 6 percent, for the 80 percent coverage example. If only HC and CO cutpoints are used, the NO_x benefit loss can be as high as 22 percent. MOBILE5 with the remote sensing utility calculates a 0.24 percent vehicle VOC and a 1.47 percent vehicle CO emission benefit in calendar year 1999 for the Phoenix gross emitter program (Grubbe, 1999; EPA, 1998).

c. Cost and Cost Effectiveness

Based on the Arizona program performance in 1999, the VOC only cost effectiveness of a gross emitter program is $10,000 per ton. Contractor charges for performing remote sensing measurements and supplying license plate numbers and emission readings are in the range of 50 cents to one dollar per vehicle. Motorist costs to those who fail the RS test would include time for an additional inspection, plus repair costs (Grubbe, 1999; EPA, 1998).

4. Heavy Duty Retrofit Programs for Highway Engines

a. Description

        Voluntary programs to upgrade or retrofit after-treatment devices to older heavy-duty engines could be a source of PM reductions in the heavy-duty highway categories. The number of engines retrofitted would vary based on the design of the local program. Based on the amount of time over which the program could be phased in, it is assumed that 25 percent of all pre-1994 highway heavy-duty engines still in the fleet in 2010 could be retrofitted (Pechan, 1997b).

b. Emission Reduction Estimate

        The resulting PM reduction was estimated to be 2.82 percent in 2010 (Pechan, 1997b).

c. Cost and Cost Effectiveness

        The costs and emission reductions associated with these programs are somewhat speculative. For this analysis, it was assumed that both highway and nonroad engines subject to the program could achieve a 25 percent reduction in PM emissions (Dolce, 1997). The cost for the heavy-duty retrofit program (for highway vehicles) is estimated at $25,500 per ton of PM_{10} reduced. This is based on the final rule for the Urban Bus Retrofit Program (58 FR 21385). These estimates are based on EPA's experience to date with the existing urban bus retrofit program, which has achieved similar reductions at similar cost (Pechan, 1997b).

5. Vehicle Retirement Programs

a. Description

        Recently, air pollution regulatory agencies and researchers have focused attention on the issue of older vehicles - those built with less effective emission control devices than today's cars and light-duty trucks. Several California air pollution control districts have adopted voluntary accelerated vehicle retirement programs, also known as vehicle buy back, cash for clunkers, or vehicle scrapping. The programs offer vehicle owners cash for their old vehicle, which is then scrapped. The potential cost effectiveness of such programs depends on the amount paid for scrapped vehicles, annual mileages for scrapped versus replacement vehicles, and respective emission rates for scrapped vs. replacement vehicles.

        One example program is in the San Francisco Bay Area. Starting in 1996, the Bay Area Air Quality Management District (BAAQMD) set aside a portion of its motor vehicle registration fee revenue to purchase and retire pre-1975 vehicles. The program expanded in 1997 to include model years 1979 and earlier and in 1998 to include model years 1981 and older. Through the end of May 1998, 1836 vehicles had been scrapped, with a contract to scrap 2,839 more. The BAAQMD program operates through contractors. Vehicle owners receive $500 per vehicle (Dill, 1999).

b. Emission Reduction Estimate

        The percentage emission reduction from 2007 baseline levels has not been estimated.

c. Cost and Cost Effectiveness

        The BAAQMD estimated that the 1997/1998 program cost $3,527 per ton of VOC and NO_X reduced. Only direct program costs were included in this calculation. Other researchers have estimated cost effectiveness for scrappage programs ranging from $2,500 to $12,500 per ton of HC and NO_x removed. This range is affected by the bounty offered for the vehicles, the number of vehicles scrapped, and other program components. This program would cost any area at least the per car purchase price ($500 to $1,000) times the number of scrapped cars

per year. Any worthwhile program would probably have to scrap 1,000 vehicles per year, at a minimum (Dill, 1999).

C.   FUEL OPTIONS

1.   Diesel

a.   Description

The quality and composition of diesel fuel can have important effects on air pollution emissions. The fuel variables having the most important effects on emissions are sulfur contant, cetane number, and the fraction of aromatic hydrocarbons contained in the fuel. 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. California's vehicle diesel fuel regulation goes beyond the Federal requirement by establishing a 500 ppm sulfur limit and requires a reduction in the aromatic content of the fuel from 30 to 10 percent.

b.   Emission Reduction Estimate

From 2007 baseline levels a 4 percent reduction in diesel-fueled vehicle NO_x emissions would be expected.

c.   Cost and Cost Effectiveness

It has been estimated that California reformulated diesel would increase the per gallon cost of diesel by 6 cents (Pechan, 1998) compared with baseline diesel.

2.   Alternative Fuel (CNG - Compressed Natural Gas)

a.   Description

This measure evaluates the possibility of requiring private fleets to purchase and use alternative fueled vehicles. Alternative fuel means a fuel other than gasoline. This assessment compares compressed natural gas vehicle benefits with those from gasoline-powered light-duty vehicles.

At a June 1999 conference on alternative fueled vehicles, EPA said that in MOBILE6, CNG vehicle emissions will be equal to the emissions of ultra-low emission vehicle (ULEV) gasoline vehicles. The NO_x emission standard for low-emission vehicles (LEVs) and ULEVs is the same, so using this analysis technique, there will be no NO_x benefits for CNG passenger cars in an area once LEV standard vehicles are sold (Kremer, 1999).

b.   Emission Reduction Estimate

The NO_x emissions difference between a Tier 1 car and a ULEV car (CNG in this case) is estimated to be 0.236 grams per mile at 65,000 accumulated miles. If the lifetime of a car is 130,000 miles and ten years, then the lifetime NO_x benefit of a CNG car compared with a Tier 1 car is 0.337 tons. Purchasing 1,000 dedicated CNG vehicles in 2000 would be expected to be a 3 ton per year NO_x credit, or 0.008 tpd.

c.   Cost and Cost Effectiveness

Current estimates are that dedicated CNG vehicle prices are about $2,500 more than those for gasoline-powered vehicles. This is based on published estimates for the CNG Toyota Camry LE. This analysis ignores the potential costs of adding fueling stations (AN, 1999).

Using a 10 year vehicle lifetime, the cost effectiveness of a CNG vehicle compared with a Tier 1 car is ($2,500)/(0.0337) tons = $74,000 per ton of NO_x.

D. TRANSPORTATION SYSTEM MODIFICATIONS

The section describes transportation system modifications with the potential for controlling emissions. Specific reductions and costs are not cited herein, as the research in this area is ongoing and often dependent upon specific regional/local parameters. The control measures described are as follows:

1.	Transit Improvements;
2.	Pricing Mechanisms;
3.	Employer Provisions of Transportation; and
4.	Voluntary Adjustment of Work Schedule.

1. Transit Improvements

This measure assumes increases in the levels of transit service (but not the geographic coverage from existing levels). It makes transit a more convenient and viable option from the typical 20-30 bus frequencies typically found outside large cities. Emissions reductions are generated from increase transit ridership, thus avoiding auto trips, cold starts, hot sinks and VMT.

Modeling would estimate new mode shares for each wait time improvement based on the expected change in travel time for each traveler and the probability of a traveler changing mode to a higher occupancy vehicle or transit. Probability of mode change is dependent both on the measure being tested and the baseline mode share. The revised vehicle estimates are converted to VMT and the VMT and vehicle reductions are translated to emissions benefits.

Improved public transit is comprised of three main components, which may effectively reduce congestion and improve air quality. The goal of improving public transit is to provide incentives for single occupancy vehicle commuters to forgo driving for the convenient and reasonably priced alternative of mass transit. The three major ways of increasing ridership on public transit are (1) system/ service expansion, (2) system/service operational improvements, and (3) inducements to travelers to increase ridership. Transportation planners should be aware that these strategies vary in risk, cost, and potential benefits.

Projects may be extremely costly if they are capital intensive (e.g., building rail lines) and rely on infrastructure changes; improvements involving transit schedules and public awareness programs are much cheaper. Examples of capital intensive projects are a dual rail/bus tunnel system in Seattle that will improve bus and rail service in the region, and a light rail line servicing Houston. These projects cost 400 million and one billion dollars, respectively.

Improving transit is effective in increasing the use of buses versus driving alone. While there is an increase in bus usage (typically 10 percent), only a portion of the increase is accounted for from lone drivers. Some increase stems from people who formerly used other high-occupancy or non-motorized modes of transportation. The overall auto trip reduction is estimated to be just under one percent.

2. Pricing Mechanisms

Pricing programs, such as an increase in the State gas tax, affect air quality primarily by reducing automobile trips and VMT. Reducing commuter trips not only reduces emissions associated with VMT, but those associated with "cold starts," when commuters set out in the morning and "hot soaks," when vehicles are parked at work and continue to produce evaporative emissions even after the engines are turned off.

Tax parking benefits and parking lots increase the cost of driving a motor vehicle by ensuring that some level of the costs of providing parking are paid by users. This is usually a peak hour measure targeting single occupant automobiles, especially those parking in suburban areas where there is usually no charge for parking. The measure also may seek to equalize the costs of transit use with driving, and to encourage other HOV modes. The measure is often

utilized in combination with incentives for non-SOV use, such as transit subsidies, flex time, etc., and may be analyzed in combination with these to capture synergistic effects.

Parking charges may be levied in a variety of manners: tax per parking space (suburban), minimum parking charges in parking garages, collected by the employer and used to cross subsidize other employee benefits (such as transit passes). The parking charge encourages ridesharing, transit and non motorized modes to avoid the full charge (e.g., rideshare people divide the cost among them) or all together (walk, bike access).

The increase in parking costs, gas taxes, and tolls result in a change in trip destinations, travel modes, and travel time periods. The goal of effecting the peak periods of travel-typically morning rush hour- and distributing overall trips, can be reached with such a measure. It is estimated that regional auto travel is marginally effected but total transit share increases by four to five percent (NCHRP, 1998).

3. Employer Provisions of Transportation/Buses to Employees

This control measure provides for employers to voluntarily provide subsidies to employees for transit and rideshare (carpool, van pool, etc.) use in lieu of drive access to the work place. These subsidies are utilized extensively in a number of areas, including Philadelphia, Washington, Boston, Baltimore, and many smaller locales. The concept seeks to avoid penalizing those employees who desire to use non-HOV modes, while parking may be provided free or at a subsidized cost to those who drive to work.

Employer based provision of transportation/buses can be simulated by providing four levels of transit subsidy to an employee: $0.50, $1.00, $1.50 and $2.00. The subsidies can be analyzed in a voluntary framework where employers would provide the subsidies on a voluntary basis entirely dependent on the employers perception of the benefits they might accrue (NCHRP, 1998).

4. Voluntary Adjustment of Work Schedule

Employees are allowed/encouraged to alter their work schedules to arrive/depart earlier/later at their work place. This reduces emissions by reducing congestion during peak commuting hours, allowing vehicles to operate at more economical and steadier speeds. This measure does NOT include flexing the days a person works, only the starting/ending time of day. Usually synergistic with transit, parking charge and other flex hours/days measures, the measure may be analyzed as such for synergistic effects.

Employer based provision of flex time work schedules should be simulated at four levels of availability: 15 percent of employees eligible, 30 percent, 45 percent and 60 percent. Regional averages for starting mode shares and average trip length can be used to provide a baseline for modeling.

Telecommuting is another way to reduce work trips. It is important to note that while the reduction in peak period trips (i.e. morning rush hour) is critical to the reduction in emissions, there are also added non-work trips during the day that offset these benefits. Errands that would have been done on the way to or from work are now done on added trips during the day. Studies by the National Cooperative Highway Research Program show that with these offsets, there can be an expected decrease in overall trips by approximately one percent.

E. REFERENCES

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CHAPTER X
NONROAD ENGINES AND VEHICLES

A.   REGULATIONS

Nonroad sources are mobile (non-highway) emission sources including lawn and garden equipment, construction equipment, agricultural equipment, industrial equipment, aircraft and airport service vehicles, logging equipment, recreational vehicles, locomotives, and marine vessels. Under the authority of the CAA, EPA has proposed or finalized regulations for a number of nonroad engine categories. The applicable regulations are listed in Table X-1.

B.   CONTROL OPTIONS

This section discusses potential control measures beyond Federal engine standards. The nonroad control measures which require new engines to meet stricter standards will require time for fleet turnover before the regulations become 100 percent effective. These new standards may include implementation of some of the control techniques listed below.

1.   Diesel-Powered Engines

Direct injection (turbocharged/aftercooled) is a control measure for PM and NO_x. The primary PM - fine control efficiency has been estimated to be between 50 percent and 80 percent (FACA, 1997). Low-sulfur diesel fuel for nonroad engines is a control measure for PM with primary PM - fine control efficiency in the range 0-50 percent (FACA, 1997).

In 1993 CARB's diesel-fuel regulations took effect. The California diesel is much more clean burning than conventional diesel fuel and its cost-effectiveness is comparable to other measures adopted in California. Switching to California diesel from conventional diesel lead to significant reductions in emission of pollutants from vehicles and equipment that used diesel fuel. There was an 82 percent reduction in SO_2, a 25 percent reduction in particulate matter, and a 7 percent reduction in NO_x. On an average the wholesale diesel prices in California have been within five cents per gallon of diesel as compared to the costs in neighboring States (CARB, 1997).

2.   Gasoline-Powered Engines

Electric motor substitution is control measure for all pollutants having a control efficiency between 80 percent and 100 percent (FACA, 1997).

Table X-1
Federal Regulations Affecting Future Year Emissions

Source Category	Applicable Regulations
Aircraft	May 8, 1997 rulemaking consistent with standards set by the United National International Civil Aviation Organization.
Railroads	Final emission standards published April 16, 1998.
Commercial Marine	Notice of Proposed Rulemaking issued for compression ignition marine engines.
Recreational Marine	Final rule published October 4, 1996. Affects spark ignition recreational marine vessels. Aimed at reducing VOC emissions.
Compression Ignition (all nonroad categories)	Tier 1 standards promulgated for engines > 50 horsepower in 1994. Tier 1 standards for small engines and tier 2 standards for all engines promulgated in August of 1998.
Spark Ignition (all nonroad categories)	Phase 1 promulgated July 1995 for small engines (at or below 19 kilowatt/25 horsepower). Phase 2 proposed December 1997, final phase 2 standards for nonhand-held small engines signed March 1999. Phase 2 Supplemental Notice of Proposed Rulemaking for new handheld engines at or below 19 kilowatt was signed June 30, 1999.

3. Locomotives

Some of the possible control measure options for NO_x reductions are listed in Table X-2 (STAPPA/ALAPCO, 1994). The source for the data is CARB. The reductions and cost information are based on California locomotive fleet parameters.

Among the new and emerging railroad technologies is the electric CyberTran rail transportation system (Manufacturer: CyberTran International, Inc.) which consists of several small, computer-controlled vehicles. It is a lightweight rail system, which can decrease congestion and since it is electrically powered it does not emit pollutants. The capital cost of a CyberTran system (2 to 4 million dollars per mile) is 10 to 50 percent of the cost of conventional light rail systems and the operational costs should also be less as compared to conventional rail and transit systems. The information about CyberTran has been obtained from the website developed by the University of California Riverside (CE-CERT, 1999).

4. Marine Compression Ignition Engines (Commercial Marine Vessels)

Selective catalytic reduction (NO_x emission reduction: 70 to 90 percent) and water/fuel emulsion (NO_x emission reduction: up to 35 percent) are two of the control measures (STAPPA/ALAPCO, 1994). The source for the data is CARB.

5. (Recreational) Marine Spark Ignition Engines

a. Marine Fuel Additive

SoyGold Marine™ (Manufacturer: AG Environmental Products, L.L.C.) is a soybean oil-based diesel fuel additive, which can be used for marine engines. The use of a 20/80 blend of SoyGold Marine™ when compared with an oxidation catalyst and low-sulfur #2 diesel showed a decrease in particulate matter emissions by 45 percent, a decrease in total hydrocarbon emissions by 65 percent, a decrease in CO emissions by 41 percent, and an increase in NO_x emissions by 7 percent. The cultivation of soybeans in order to produce this product leads to a consumption of six times more CO_2 than emitted during its use. Generally this product will cost $0.60 to 0.80 per gallon more than petroleum diesel. The information about SoyGold Marine™ has been obtained from the website developed by the University of California Riverside (CE-CERT, 1999).

b. Credits for Replacement of Existing Pleasure Craft Engines with New Lower Polluting Engines

This control measure focuses on the accelerated replacement of existing pleasure craft engines with lower polluting engines. Pleasure craft are recreational marine vessels. This control measure includes the development of an emission reduction credit program. This would allow the governing body to issue emission reduction credits for programs that accelerate the replacement of existing pleasure craft engines with lower polluting engines. Such a program would be voluntarily implemented and would provide industry with more flexible and potentially more cost effective approaches in complying with SIP requirements. Program operators would qualify for emission reduction credits by replacing existing uncontrolled engines with new engines that meet EPA emission

Table X-2
Control Measures for NO$_x$ Reductions from Locomotives

Control Measure	NO$_x$ Reduced	Cost Effectiveness ($/ton)
Electric line haul, liquified natural gas (LNG) + SCR, local/switch	99%	14,800
Engine Modifications	38%	3,200
LNG and SCR	97%	1,900
LNG dual-fuel	70%	900
LNG dual-fuel line haul, remanufacture/replace local/switch	72%	1,700
LNG dual-fuel line haul, LNG, spark ignition local/switch	80%	900
LNG, spark ignition	86%	1,400
Low-aromatic diesel fuel	10%	5,000
Selective catalytic reduction	90%	2,900

standards. This is based on SCAQMD Proposed Rule 1624. The cost per ton of VOC and NO_x reduction has not yet been determined (SCAQMD, 1999).

6. Airport

a. Electric Vehicles

The use of electric vehicles in airports is a new and emerging air pollution control program.   The hybrid-electric prototype T-1000 Neighborhood Truck (Manufacturer: Coval H2 Partners) which can be used as a maintenance vehicle is powered by a fuel cell and is a zero-emission vehicle. The ThunderVolt 701AT electric power train (Manufacturer: ISE Research) is a zero emission vehicle. It is used as a drive system for several types of aircraft specialty equipment. As compared to regular power trains it has 10-20 percent lower maintenance costs. Information about the electric vehicles has been obtained from the website developed by the University of California Riverside (CE-CERT, 1999).

b. Liquified Petroleum Gas-Fueled Vans for Rental Car Company Shuttles

This control measure is to substitute propane-fueled vehicles for the vans that transport passengers from rental car lots to terminals and vice-versa. The emission benefits (tpd) are 0.005 for VOC and 0.003 for NO_x. For this control measure the cost-effectiveness has been estimated to be \$24,200/ton for VOC and \$40,900/ton for NO_x. The key assumptions in determining the cost-effectiveness are: i) the incremental vehicle cost is \$3,000, amortized for 8 years, ii) the fueling station cost is \$79,000, amortized for 10 years, and iii) the fuel cost savings are \$.0059 per mile (conventional gasoline vs. propane). Shuttle operations, with limited range requirements and centralized fleet characteristics, can be a good application for alternative fuel technologies. In this instance, the lower cost of propane (based on the U.S. Department of Energy (DOE) study) indicates that an option that reduces emissions can also reduce cost. Cost-effectiveness is greatly influenced by the fuel cost. However, the small number of vehicles and miles generates very little VOC and NO_x savings (Molle, 1992; DOE, 1996).

7. Commercial/Industrial Mobile Equipment

The Envirolift ECD (Emission Control Device, Manufacturer: Envirolift) has been designed as an emission control device for emissions from four or six cylinder engines. It can be used for gas and liquid propane (LP) equipment like Forklifts, Manlifts, and Scrubber/Sweepers. It significantly reduces emissions of CO and HC. Its emission reduction capacity is up to ten times more than a catalytic converter, after the converter has reached a temperature of 600 degrees Farenheit. The ECD unit costs around \$1500, plus installation. Information about Envirolift was obtained from the website developed by the University of California Riverside (CE-CERT, 1999).

8. Lawn and Garden Equipment

a. Electric Lawnmowers

Cordless, electric lawnmowers are available in the marketplace.   The Cordless Mulching Mower (Model CMM1000, Manufacturer: Black and Decker) is powered by improved batteries, which increase the operation time. Cordless mowers cost a little more than conventional gasoline mowers. The operational cost for battery charging is around \$3/year. During operation cordless mowers do not create emissions but some emissions are created during the recharging. The LawnPup (Manufacturer: GrassMasters) is a compact electric lawn mower. The LawnPup 1000 model costs around \$180. The use of electrical engines can lead to a reduction in emissions of particulates by 91 percent, CO by 76 percent, and VOCs by 82 percent. The TrimmerPlus 1090r trimmer (Manufacturer: Ryobi Outdoor Products, Inc.) is equipped with a Ryobi second generation gas-powered 4-cycle engine, which is much more efficient than other 4-stroke engines and is cleaner than 2-stroke engines. Compared to standard mowers, it reduces

exhaust pollutants by 80 percent and costs $250.00. Information about these lawn and garden equipment was obtained from the website developed by the University of California Riverside (CE-CERT, 1999).

A control measure to control emissions from lawn and garden equipment is to provide incentives for electric lawnmowers and to subsidize them. During the spring and summer of 1995, the Maryland Department of the Environment implemented Cash-for-Clippers, a lawn and garden equipment trade-in program. Through Cash-for-Clippers, Maryland provided $75 rebates toward the purchase of environmentally friendly (electric or push mowers) lawn equipment to individuals who scrapped their gasoline-powered equipment. For hand-held equipment, the rebates were $25. Compared with a gasoline-powered mower meeting EPA's 1997 emission standards, a cordless mower has 99.9 percent lower VOC emissions. The market penetration of electric lawnmowers depends on their cost relative to gasoline-powered mowers (as long as their performance is perceived to be the same as a gasoline-powered mower). Cost effectiveness calculations are based on residential use replacement, and the rebate amount ($75 for lawnmowers) is about equal to the price difference between electrics and gasoline-powered mowers (associated SCCs: 2260004010, 2265004010). Emission reductions are based on 10 percent market penetration by 2005 of battery-powered lawn and garden equipment. The cost-effectiveness when considering only consumer equipment is estimated to be $1172 per ton of VOC (MDE, 1996a; EPA, 1991; EPRI, 1996a; EPRI, 1996b).

b. Leakless Gasoline Can Nozzles

This measure involves using vapor recovery nozzles to control refueling emissions from the refueling of lawn and garden equipment. Special nozzles are available with an automatic stop device. They work by keeping the gasoline from pouring until the nozzle is inserted in the tank, stopping flow automatically when the tank becomes full, and sealing the container when the nozzle is removed from the tank. For a small nozzle in typical residential use, the cost-effectiveness of the vapor recovery nozzle is $1,400 to $5,800 per ton of VOC depending on the gasoline quantity used during the summer season. Because the nozzle provides fuel savings, more gasoline usage produces a lower cost per ton. In commercial use, fuel savings outweigh the nozzle cost, so the cost effectiveness is a savings of $130 to $290 per ton (MDE, 1996b; VEMCO, 1996a; VEMCO, 1996b).

9. Container Spillage Control Measures

This control measure would reduce VOC emissions from portable fuel containers used to refuel off-road equipment by replacing the current style of portable containers with a spill-proof container system. These spill-proof container systems would eliminate overfilling spillage and would substantially mitigate container transport and storage, container diurnal, and container permeation emissions (CARB, 1999). The proposed regulations would apply to new cans and spouts that are sold in California starting January 1, 2001 (CARB, 1999). The measure will be implemented through compliance testing and the attrition of noncompliant portable fuel containers (Bloudoff, 1999). Full compliance with the proposed measure is expected by 2007, assuming an average container service life of six years (Bloudoff, 1999). The associated SCCs for this control measure are 2260004000 and 2265004000.

Spill-proof containers would automatically stop the flow of fuel before overflow of the target fuel tank, automatically close and seal when removed from the target fuel tank, and remain completely closed when not dispensing fuel. Filling and pouring would both be through the same opening, and the minimum flow rate would be one-half gallon per minute for the smallest portable fuel containers, and higher for larger containers (CARB, 1999). The container would be made of materials which ensure that the vapor permeation rate does not exceed 0.4 grams per gallon per day (CARB, 1999).

About 87 tpd of smog-forming ROG are released into California's air from portable gas cans. The proposed regulations being adopted will lead to a 73 percent reduction in ROG emissions from gas cans by 2010. CARB estimates that the cost of the proposed regulation would be $4020 for each ton of ROG reduced (CARB, 1999).

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16. ABSTRACT

This report contains a description of control measures that are contained with the ControlNET database. The control m
for reductions of emissions each of the criteria pollutants that the Environmental Protection Agency (EPA) regulates.
measures can be applied to sources that are contained in the National Emission Trends (NET) Inventory, a comprehens
of criteria pollutant emission sources for which EPA has data.   This database is meant to serve as a repository of curre
measure data for use in analyses EPA conducts in support of its air pollution regulations.

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