United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park, NC 27711

AP-42
Volume I
Supplement F
July 1993

Air

EPA

AP42F

SUPPLEMENT F

TO

COMPILATION OF AIR POLLUTANT EMISSION FACTORS

VOLUME I:

STATIONARY POINT AND AREA SOURCES

U.S. Environmental Protection Agency
Region 5, Library (PL-12J)
77 West Jackson Boulevard, 12th Floor
Chicago, IL 60604-3590

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

NOTICE

The Emission Inventory Branch (EIB) has been working on this *Supplement F* to AP-42 for several months. It is a substantial part of EPA's efforts to comply with Section 130 of the 1990 Clean Air Act Amendments, which require that the Agency review and revise its air pollutant emission factors every three years. *Supplements D* and *E* reflected the first parts of this effort. Though the Act requires this updating for ozone-related pollutants only (total organic compounds, oxides of nitrogen, and carbon monoxide), the effort has been expanded to include, where data are available, other criteria pollutants, hazardous pollutants, global warming gases and other speciation information. More AP-42 sections are now under development and/or review, to result in the cover to cover update of this important document series. This complete update has been a major technical undertaking, and the efforts of the Emission Factor And Methodologies Section staff, and of the several contractors who assisted, are hereby acknowledged.

This supplement and the subsequent updates now under development represent significant improvements, but many data gaps and uncertainties still exist. AP-42 users can help alleviate this situation by providing comments, emission test data, and any other information which may be evaluated and reflected in future updates.

Those familiar with this document may notice that some factors published in the past now have lower quality ratings, even though the factors are unchanged or are supported by newer and more extensive data. This is attributable to the adoption of more consistent and stringently applied rating criteria. The factors in this AP-42 update are believed to be more appropriate and to represent a better estimate than in the past. Of course, they remain for estimation purposes and should not be considered substitutes for exact measurements taken at the source.

Besides this print medium, the information in AP-42 is now available by several other routes. The *Air CHIEF* compact disc/read-only memory (CD/ROM) contains AP-42, as well as about 30 hazardous air pollutant emission estimation reports and several data bases. It can be purchased from the Government Printing Office for about $15.00. Also, the *CHIEF* electronic bulletin board, via PC/modem at (919) 541-5742, contains the latest versions of each section of AP-42, and many other reports and tools. In addition, individual sections of AP-42 can be obtained quickly and directly through the facsimile service *Fax CHIEF*, at 919) 541-5626/0548. These electronic on-line services operate 24 hours per day and 7 days per week. *The CHIEF Newsletter*, issued quarterly, contains much useful information on emission factors, inventories and related matters, and anyone may receive this newsletter by providing her/his name and address. These various media are provided by EIB's ClearingHouse For Inventories And Emission Factors (CHIEF).

If you have questions or comments, on these or any other emission estimation topics, you may call the *Info CHIEF* hot line at 919 541-5285, during Eastern Time office hours, or write to:

Emission Inventory Branch (MD 14)
US EPA
Research Triangle Park, NC 27711

Emission Factor And Methodologies Section
Emission Inventory Branch
Technical Support Division
Office Of Air Quality Planning And Standards
U. S. Environmental Protection Agency

INSTRUCTIONS FOR INSERTING

SUPPLEMENT F

INTO VOLUME I OF AP-42

Pp. iii through vi (blank) replace iii and iv. New "Publications In Series".

Pp. vii through x replace v through viii. New "Contents".

Pp. xi through xviii replace ix through xvi. New "Key Word Index".

Pp. 1.1-1 through -38 (blank) replace all of previous Section 1.1. Major Revision.

Pp. 1.2-1 through -14 (blank) replace all previous. Major Revision.

Pp. 1.3-1 through -38 replace all previous. Major Revision.

Pp. 1.4-1 through -8 replace all previous. Major Revision.

Pp. 1.5-1 through -6 (blank) replace all previous. Major Revision.

Pp. 1.6-1 through -18 replace all previous. Major Revision.

Pp. 1.7-1 through -18 (blank) replace all previous. Major Revision.

Pp. 1.8-1 through -6 (blank) replace all previous. Major Revision.

Pp. 1.9-1 through -6 (blank) replace all previous. Major Revision.

Pp. 1.10-1 through -12 replace all previous. Major Revision.

Pp. 1.11-1 through -8 replace all previous. Major Revision.

Pp. 2.1-1 through -44 replace all previous. Major Revision.

Pp. 2.5-1 through -56 (blank) replace all previous. Major Revision.

Add pp. 2.6-1 through -30. New Section.

Add pp. 2.7-1 through -14 (blank). New Section.

Pp. 3.1-1 through -10 replace all previous. Minor Revision.

Pp. 3.2-1 through -10 (blank) replace all previous. Minor Revision.

Pp. 3.3-1 through -8 (blank) replace all previous. Minor Revision.

Pp. 3.4-1 through -10 (blank) replace all previous. Minor Revision.

Pp. 5.2-1 through -6 replace all previous. Major Revision.

Pp. 5.5-1 through -6 replace all previous. Major Revision.

Pp. 5.7-1 through -4 replace all previous. Major Revision.

Pp. 5.8-1 through -6 replace all previous. Major Revision.

Pp. 5.9-1 through -8 (blank) replace all previous. Major Revision.

Pp. 5.11-1 through -10 (blank) replace all previous. Major Revision.

Pp. 5.15-1 through -8 (blank) replace all previous. Major Revision.

Pp. 5.16-1 through -8 replace all previous. Major Revision.

Pp. 5.17-1 through -10 (blank) replace all previous. Major Revision.

Pp. 5.18-1 through -6 replace all previous. Major Revision.

INSTRUCTIONS FOR INSERTING **SUPPLEMENT F**

(CONT.)

Pp. 6.8-1 through -10 replace all previous. Major Revision.

Add pp. 6.10-1 and -2 (blank). Editorial Change.

Pp. 6.10.1-1 through -4 replace all previous. Major Revision.

Pp. 6.10.2-1 through -6 (blank) replace all previous. Major Revision.

Pp. 6.10.3-1 through -6 (blank) replace all previous. Major Revision.

Pp. 6.14-1 through -8 replace all previous. Major Revision.

Pp. 6.18-1 through -4 replace all previous. Major Revision.

Pp. 7.7-1 through -8 replace all previous. Major Revision.

Pp. 7.14-1 through -10 replace all previous. Major Revision.

Pp. 7.16-1 through -6 replace all previous. Major Revision.

Pp. 8.8-1 through -4 replace all previous. Editorial Change.

Pp. 8.10-1 through -6 (blank) replace all previous. Editorial Change.

Pp. 8.11-1 through -16 replace all previous. Editorial Change.

Pp. 8.14-1 through -10 replace all previous. Major Revision.

Pp. 8.16-1 through -12 (blank) replace all previous. Major Revision.

Pp. 8.17-1 through -6 (blank) replace all previous. Major Revision.

Pp. 8.18-1 through -12 replace all previous. Major Revision.

Pp. 8.23-1 through -8 (blank) replace all previous. Editorial Change.

Add pp. 8.25-1 through -10. New Section.

Section 8.26 is reserved.

Add pp. 8.27-1 through -4. New Section.

Pp. 12-1 through -4 and -39 and -40 replace same. Minor Revision.

Pp. D-1 through -12 (blank) replace all previous. Major Revision.

Pp. E-1 through -8 (blank) replace all previous. Major Revision.

AP-42
Volume I
Supplement F

SUPPLEMENT F

TO

COMPILATION OF AIR POLLUTANT EMISSION FACTORS

VOLUME I:

STATIONARY POINT AND AREA SOURCES

Office Of Air Quality Planning And Standards
Office Of Air And Radiation
U. S. Environmental Protection Agency
Research Triangle Park, NC 27711

July 1993

This report has been reviewed by the Office Of Air Quality Planning And Standards, U. S. Environmental Protection Agency, and has been approved for publication. Any mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use.

AP-42
Volume I
Supplement F

PUBLICATIONS IN SERIES

Issue			*Date*
COMPILATION OF AIR POLLUTANT EMISSION FACTORS, FOURTH EDITION			9/85
SUPPLEMENT A			10/86
Introduction			
Section	1.1	Bituminous And Subbituminous Coal Combustion	
	1.2	Anthracite Coal Combustion	
	1.3	Fuel Oil Combustion	
	1.4	Natural Gas Combustion	
	1.6	Wood Waste Combustion In Boilers	
	1.7	Lignite Combustion	
	5.16	Sodium Carbonate	
	7.1	Primary Aluminum Production	
	7.2	Coke Production	
	7.3	Primary Copper Smelting	
	7.4	Ferroalloy Production	
	7.5	Iron And Steel Production	
	7.6	Primary Lead Smelting	
	7.7	Zinc Smelting	
	7.8	Secondary Aluminum Operations	
	7.10	Gray Iron Foundries	
	7.11	Secondary Lead Processing	
	8.1	Asphaltic Concrete Plants	
	8.3	Bricks And Related Clay Products	
	8.6	Portland Cement Manufacturing	
	8.10	Concrete Batching	
	8.13	Glass Manufacturing	
	8.15	Lime Manufacturing	
	8.19.2	Crushed Stone Processing	
	8.22	Taconite Ore Processing	
	8.24	Western Surface Coal Mining	
	10.1	Chemical Wood Pulping	
	11.2.6	Industrial Paved Roads	
Appendix	C.1	Particle Size Distribution Data And Sized Emission Factors For Selected Sources	
Appendix	C.2	Generalized Particle Size Distributions	
SUPPLEMENT B			9/88
Section	1.1	Bituminous And Subbituminous Coal Combustion	
	1.2	Anthracite Coal Combustion	
	1.10	Residential Wood Stoves	
	1.11	Waste Oil Combustion	
	2.1	Refuse Combustion	
	2.5	Sewage Sludge Incineration	
	4.2	Surface Coating	
	4.12	Polyester Resin Plastics Product Fabrication	
	5.15	Soap And Detergents	
	6.4	Grain Elevators And Processing Plants	
	8.15	Lime Manufacturing	
	8.19.2	Crushed Stone Processing	
	11.1	Wildfires And Prescribed Burning	
	11.2.1	Unpaved Roads	
	11.2.3	Aggregate Handling And Storage Piles	
	11.2.6	Industrial Paved Roads	
	11.2.7	Industrial Wind Erosion	
Appendix	C.3	Silt Analysis Procedures	

PUBLICATIONS IN SERIES (Cont.)

Issue			*Date*
SUPPLEMENT C			9/90
Section	1.10	Residential Wood Stoves	
	2.1	Refuse Combustion	
	2.5	Sewage Sludge Incineration	
	4.2.2.13	Magnetic Tape Manufacturing Industry	
	4.2.2.14	Surface Coating Of Plastic Parts For Business Machines	
	5.19	Synthetic Fiber Manufacturing	
	7.6	Primary Lead Smelting	
	7.10	Gray Iron Foundries	
	10.1	Chemical Wood Pulping	
	11.1	Wildfires And Prescribed Burning	
	11.2.6	Industrial Paved Roads	
	11.2.7	Industrial Wind Erosion	
	11.3	Explosives Detonation	
Appendix	C.2	Generalized Particle Size Distributions	
Appendix	D	Procedures For Sampling Surface/Bulk Dust Loading	
Appendix	E	Procedures For Laboratory Analysis Of Surface/Bulk Dust Loading Samples	
SUPPLEMENT D			9/91
Section	1.4	Natural Gas Combustion	
	1.9	Residential Fireplaces	
	1.10	Residential Wood Stoves	
	2.1	Refuse Combustion	
	4.2.1	Nonindustrial Surface Coating	
	4.13	Waste Water Collection, Treatment And Storage	
	5.13.1	Polyvinyl Chloride And Polypropylene	
	5.13.2	Poly(ethylene terephthalate)	
	5.13.3	Polystyrene	
	6.10.3	Ammonium Phosphates	
	8.6	Portland Cement Manufacturing	
	8.19.1	Sand And Gravel Processing	
	8.24	Western Surface Coal Mining	
	11.1	Wildfires And Prescribed Burning	
	11.4	Wet Cooling Towers	
	11.5	Industrial Flares	
SUPPLEMENT E			10/92
Section	1.2	Anthracite Coal Combustion	
	1.4	Natural Gas Combustion	
	1.5	Liquified Petroleum Gas Combustion	
	1.6	Wood Waste Combustion In Boilers	
	1.8	Bagasse Combustion In Sugar Mills	
	1.9	Residential Fireplaces	
	1.10	Residential Wood Stoves	
	1.11	Waste Oil Combustion	
	2.2	Automobile Body Incineration	
	2.3	Conical Burners	
	2.4	Open Burning	
	3.1	Stationary Gas Turbines For Electricity Generation	
	3.2	Heavy Duty Natural Gas Fired Pipeline Compressor Engines	
	3.3	Gasoline And Diesel Industrial Engines	
	3.4	Large Stationary Diesel And All Stationary Dual Fuel Engines	
	5.15	Soap And Detergents	
Chapter	12	Storage Of Organic Liquids	

PUBLICATIONS IN SERIES (Cont.)

SUPPLEMENT F 7/93

Section	1.1	Bituminous And Subbituminous Coal Combustion
	1.2	Anthracite Coal Combustion
	1.3	Fuel Oil Combustion
	1.4	Natural Gas Combustion
	1.5	Liquefied Petroleum Gas Combustion
	1.6	Wood Waste Combustion In Boilers
	1.7	Lignite Combustion
	1.8	Bagasse Combustion In Sugar Mills
	1.9	Residential Fireplaces
	1.10	Residential Wood Stoves
	1.11	Waste Oil Combustion
	2.1	Refuse Combustion
	2.5	Sewage Sludge Incineration
	2.6	Medical Waste Incineration
	2.7	Landfills
	3.1	Stationary Gas Turbines For Electricity Generation
	3.2	Heavy Duty Natural Gas Fired Pipeline Compressor Engines
	3.3	Gasoline And Diesel Industrial Engines
	3.4	Large Stationary Diesel And All Stationary Dual Fuel Engines
	5.2	Synthetic Ammonia
	5.5	Chlor-Alkali
	5.7	Hydrochloric Acid
	5.8	Hydrofluoric Acid
	5.9	Nitric Acid
	5.11	Phosphoric Acid
	5.15	Soap And Detergents
	5.16	Sodium Carbonate
	5.17	Sulfuric Acid
	5.18	Sulfur Recovery
	6.8	Ammonium Nitrate
	6.10.1	Normal Superphosphates
	6.10.2	Triple Superphosphates
	6.10.3	Ammonium Phosphate
	6.14	Urea
	6.18	Ammonium Sulfate
	7.7	Zinc Smelting
	7.14	Secondary Zinc Processing
	7.16	Lead Oxide And Pigment Production
	8.8	Clay And Fly Ash Sintering
	8.10	Concrete Batching
	8.11	Glass Fiber Manufacturing
	8.14	Gypsum Processing
	8.16	Mineral Wool Processing
	8.17	Perlite Processing
	8.18	Phosphate Rock Processing
	8.23	Metallic Minerals Processing
	8.25	Lightweight Aggregate Manufacturing
	8.27	Feldspar Processing
Chapter	12	Storage Of Organic Liquids
Appendix	D	Procedures For Sampling Surface And Bulk Materials
Appendix	E	Procedures For Analyzing Surface And Bulk Material Samples

CONTENTS

Page

INTRODUCTION 1

1. EXTERNAL COMBUSTION SOURCES 1-1
   - 1.1 Bituminous And Subbituminous Coal Combustion 1.1-1
   - 1.2 Anthracite Coal Combustion 1.2-1
   - 1.3 Fuel Oil Combustion 1.3-1
   - 1.4 Natural Gas Combustion 1.4-1
   - 1.5 Liquified Petroleum Gas Combustion 1.5-1
   - 1.6 Wood Waste Combustion In Boilers 1.6-1
   - 1.7 Lignite Combustion 1.7-1
   - 1.8 Bagasse Combustion In Sugar Mills 1.8-1
   - 1.9 Residential Fireplaces 1.9-1
   - 1.10 Residential Wood Stoves 1.10-1
   - 1.11 Waste Oil Combustion 1.11-1

2. SOLID WASTE DISPOSAL 2.0-1
   - 2.1 Refuse Combustion 2.1-1
   - 2.2 Automobile Body Incineration 2.2-1
   - 2.3 Conical Burners 2.3-1
   - 2.4 Open Burning 2.4-1
   - 2.5 Sewage Sludge Incineration 2.5-1
   - 2.6 Medical Waste Incineration 2.6-1
   - 2.7 Landfills 2.7-1

3. STATIONARY INTERNAL COMBUSTION SOURCES 3.0-1
   - Glossary Of Terms ..... Vol. II
   - Highway Vehicles ..... Vol. II
   - Off-highway Mobile Sources ..... Vol. II
   - 3.1 Stationary Gas Turbines For Electricity Generation 3.1-1
   - 3.2 Heavy Duty Natural Gas Fired Pipeline Compressor Engines 3.2-1
   - 3.3 Gasoline And Diesel Industrial Engines 3.3-1
   - 3.4 Large Stationary Diesel And All Stationary Dual Fuel Engines 3.4-1

4. EVAPORATION LOSS SOURCES 4.1-1
   - 4.1 Dry Cleaning 4.1-1
   - 4.2 Surface Coating 4.2-1
   - 4.2.1 Nonindustrial Surface Coating 4.2.1-1
   - 4.2.2 Industrial Surface Coating 4.2.2.1-1
   - 4.2.2.1 General Industrial Surface Coating 4.2.2.1-1
   - 4.2.2.2 Can Coating 4.2.2.2-1
   - 4.2.2.3 Magnet Wire Coating 4.2.2.3-1
   - 4.2.2.4 Other Metal Coating 4.2.2.4-1
   - 4.2.2.5 Flat Wood Interior Panel Coating 4.2.2.5-1
   - 4.2.2.6 Paper Coating 4.2.2.6-1
   - 4.2.2.7 Fabric Coating 4.2.2.7-1
   - 4.2.2.8 Automobile And Light Duty Truck Surface Coating Operations 4.2.2.8-1
   - 4.2.2.9 Pressure Sensitive Tapes And Labels 4.2.2.9-1
   - 4.2.2.10 Metal Coil Surface Coating 4.2.2.10-1
   - 4.2.2.11 Large Appliance Surface Coating 4.2.2.11-1
   - 4.2.2.12 Metal Furniture Surface Coating 4.2.2.12-1
   - 4.2.2.13 Magnetic Tape Manufacturing 4.2.2.13-1
   - 4.2.2.14 Surface Coating Of Plastic Parts For Business Machines 4.2.2.14-1
   - 4.3 [Reserved]
   - 4.4 Transportation And Marketing Of Petroleum Liquids 4.4-1
   - 4.5 Cutback Asphalt, Emulsified Asphalt And Asphalt Cement 4.5-1
   - 4.6 Solvent Degreasing 4.6-1

4.7 Waste Solvent Reclamation 4.7-1
4.8 Tank And Drum Cleaning 4.8-1
4.9 Graphic Arts 4.9-1
4.10 Commercial/Consumer Solvent Use 4.10-1
4.11 Textile Fabric Printing 4.11-1
4.12 Polyester Resin Plastics Product Fabrication 4.12-1
4.13 Waste Water Collection, Treatment And Storage 4.13-1

5. CHEMICAL PROCESS INDUSTRY 5.1-1
5.1 Adipic Acid 5.1-1
5.2 Synthetic Ammonia 5.2-1
5.3 Carbon Black 5.3-1
5.4 Charcoal 5.4-1
5.5 Chlor-Alkali 5.5-1
5.6 Explosives 5.6-1
5.7 Hydrochloric Acid 5.7-1
5.8 Hydrofluoric Acid 5.8-1
5.9 Nitric Acid 5.9-1
5.10 Paint And Varnish 5.10-1
5.11 Phosphoric Acid 5.11-1
5.12 Phthalic Anhydride 5.12-1
5.13.1 Polyvinyl Chloride And Polypropylene 5.13.1-1
5.13.2 Poly(ethylene terephthalate) 5.13.2-1
5.13.3 Polystyrene 5.13.3-1
5.14 Printing Ink 5.14-1
5.15 Soap And Detergents 5.15-1
5.16 Sodium Carbonate 5.16-1
5.17 Sulfuric Acid 5.17-1
5.18 Sulfur Recovery 5.18-1
5.19 Synthetic Fibers 5.19-1
5.20 Synthetic Rubber 5.20-1
5.21 Terephthalic Acid 5.21-1
5.22 Lead Alkyl 5.22-1
5.23 Pharmaceuticals Production 5.23-1
5.24 Maleic Anhydride 5.24-1

6. FOOD AND AGRICULTURAL INDUSTRY 6.1-1
6.1 Alfalfa Dehydrating 6.1-1
6.2 Coffee Roasting 6.2-1
6.3 Cotton Ginning 6.3-1
6.4 Grain Elevators And Processing Plants 6.4-1
6.5 Fermentation 6.5-1
6.6 Fish Processing 6.6-1
6.7 Meat Smokehouses 6.7-1
6.8 Ammonium Nitrate 6.8-1
6.9 Orchard Heaters 6.9-1
6.10 Phosphate Fertilizers 6.10-1
6.11 Starch Manufacturing 6.11-1
6.12 Sugar Cane Processing 6.12-1
6.13 Bread Baking 6.13-1
6.14 Urea 6.14-1
6.15 Beef Cattle Feedlots 6.15-1
6.16 Defoliation And Harvesting Of Cotton 6.16-1
6.17 Harvesting Of Grain 6.17-1
6.18 Ammonium Sulfate 6.18-1

7. METALLURGICAL INDUSTRY 7.1-1
7.1 Primary Aluminum Production 7.1-1
7.2 Coke Production 7.2-1

7.3 Primary Copper Smelting 7.3-1
7.4 Ferroalloy Production 7.4-1
7.5 Iron And Steel Production 7.5-1
7.6 Primary Lead Smelting 7.6-1
7.7 Zinc Smelting 7.7-1
7.8 Secondary Aluminum Operations 7.8-1
7.9 Secondary Copper Smelting And Alloying 7.9-1
7.10 Gray Iron Foundries 7.10-1
7.11 Secondary Lead Processing 7.11-1
7.12 Secondary Magnesium Smelting 7.12-1
7.13 Steel Foundries 7.13-1
7.14 Secondary Zinc Processing 7.14-1
7.15 Storage Battery Production 7.15-1
7.16 Lead Oxide And Pigment Production 7.16-1
7.17 Miscellaneous Lead Products 7.17-1
7.18 Leadbearing Ore Crushing And Grinding 7.18-1

8. MINERAL PRODUCTS INDUSTRY 8.1-1
8.1 Asphaltic Concrete Plants 8.1-1
8.2 Asphalt Roofing 8.2-1
8.3 Bricks And Related Clay Products 8.3-1
8.4 Calcium Carbide Manufacturing 8.4-1
8.5 Castable Refractories 8.5-1
8.6 Portland Cement Manufacturing 8.6-1
8.7 Ceramic Clay Manufacturing 8.7-1
8.8 Clay And Fly Ash Sintering 8.8-1
8.9 Coal Cleaning 8.9-1
8.10 Concrete Batching 8.10-1
8.11 Glass Fiber Manufacturing 8.11-1
8.12 Frit Manufacturing 8.12-1
8.13 Glass Manufacturing 8.13-1
8.14 Gypsum Manufacturing 8.14-1
8.15 Lime Manufacturing 8.15-1
8.16 Mineral Wool Manufacturing 8.16-1
8.17 Perlite Manufacturing 8.17-1
8.18 Phosphate Rock Processing 8.18-1
8.19 Construction Aggregate Processing 8.19-1
8.20 [Reserved]
8.21 Coal Conversion 8.21-1
8.22 Taconite Ore Processing 8.22-1
8.23 Metallic Minerals Processing 8.23-1
8.24 Western Surface Coal Mining 8.24-1
8.25 Lightweight Aggregate Manufacturing 8.25-1
8.26 [Reserved]
8.27 Feldspar Processing 8.27-1

9. PETROLEUM INDUSTRY 9.1-1
9.1 Petroleum Refining 9.1-1
9.2 Natural Gas Processing 9.2-1

10. WOOD PRODUCTS INDUSTRY 10.1-1
10.1 Chemical Wood Pulping 10.1-1
10.2 Pulpboard 10.2-1
10.3 Plywood Veneer And Layout Operations 10.3-1
10.4 Woodworking Waste Collection Operations 10.4-1

11. MISCELLANEOUS SOURCES 11.1-1
11.1 Wildfires And Prescribed Burning 11.1-1
11.2 Fugitive Dust Sources 11.2-1

11.3 Explosives Detonation 11.3-1
11.4 Wet Cooling Towers 11.4-1
11.5 Industrial Flares 11.5-1

12. STORAGE OF ORGANIC LIQUIDS 12-1

APPENDIX A
Miscellaneous Data And Conversion Factors A-1

APPENDIX B
(Reserved For Future Use)

APPENDIX C.1
Particle Size Distribution Data And Sized Emission Factors For Selected Sources C.1-1

APPENDIX C.2
Generalized Particle Size Distributions C.2-1

APPENDIX C.3
Silt Analysis Procedures C.3-1

APPENDIX D
Procedures For Sampling Surface/Bulk Dust Loading D-1

APPENDIX E
Procedures For Laboratory Analysis Of Surface/Bulk Dust Loading Samples E-1

KEY WORD INDEX

CHAPTER/SECTION

Acid
  Adipic 5.1
  Hydrochloric 5.7
  Hydrofluoric 5.8
  Phosphoric 5.11
  Sulfuric 5.17
  Terephthalic 5.21
Adipic Acid 5.1
Aggregate, Construction 8.19
Aggregate, Lightweight 8.25
Aggregate Storage Piles
  Fugitive Dust 11.2
Agricultural Tilling
  Fugitive Dust 11.2
Alfalfa Dehydrating 6.1
Alkali, Chlor- 5.5
Alloys
  Ferroalloy Production 7.4
  Secondary Copper Smelting And Alloying 7.9
Aluminum
  Primary Production 7.1
  Secondary Operations 7.8
Ammonia, Synthetic 5.2
Ammonium Nitrate 6.8
Ammonium Phosphate 6.10.3
Anhydride, Phthalic 5.12
Anthracite Coal Combustion 1.2
Appliance Surface Coating 4.2.2.11
Ash
  Fly Ash Sintering 8.8
Asphalt
  Cutback Asphalt, Emulsified Asphalt And Asphalt Cement 4.5
  Roofing 8.2
Asphaltic Concrete Plants 8.1
Automobile Body Incineration 2.2
Automobile Surface Coating 4.2.2.8-1

Bagasse Combustion In Sugar Mills 1.8
Baking, Bread 6.13
Bark
  Wood Waste Combustion In Boilers 1.6
Batching, Concrete 8.10
Battery
  Storage Battery Production 7.15
Beer Production
  Fermentation 6.5
Bituminous Coal Combustion 1.1
Bread Baking 6.13
Bricks And Related Clay Products 8.3
Bulk Material Analysis Procedures ..... App. E
Bulk Material Sampling Procedures ..... App. D
Burners, Conical (Teepee) 2.3

Burning, Open 2.4
Business Machines, Plastic Parts Coating 4.2.2.14

Calcium Carbide Manufacturing 8.4
Can Coating 4.2.2.2
Cane
  Sugar Cane Processing 6.12
Carbon Black 5.3
Carbonate
  Sodium Carbonate Manufacturing 5.16
Castable Refractories 8.5
Cattle
  Beef Cattle Feedlots 6.15
Cement
  Asphalt 4.5
  Portland Cement Manufacturing 8.6
Ceramic Clay Manufacturing 8.7
Charcoal 5.4
Chemical Wood Pulping 10.1
Chlor-Alkali 5.5
Clay
  Bricks And Related Clay Products 8.3
  Ceramic Clay Manufacturing 8.7
  Clay And Fly Ash Sintering 8.8
Cleaning
  Coal 8.9
  Dry Cleaning 4.1
  Tank And Drum 4.8
Coal
  Anthracite Coal Combustion 1.2
  Bituminous Coal Combustion 1.1
  Cleaning 8.9
  Conversion 8.21
Coating, Surface 4.2
  Appliance, Large 4.2.2.11
  Automobile And Light Duty Truck 4.2.2.8
  Can 4.2.2.2
  Fabric 4.2.2.7
  Flat Wood Interior Panel 4.2.2.5
  Metal, General 4.2.2.4
  Magnet Wire 4.2.2.3
  Magnetic Tape 4.2.2.13
  Metal Coil Surface 4.2.2.10
  Metal Furniture 4.2.2.12
  Paper 4.2.2.6
  Plastic Parts For Business Machines 4.2.2.14
  Tapes And Label, Pressure Sensitive 4.2.2.9
Coffee Roasting 6.2
Coke Manufacturing 7.2
Combustion
  Anthracite Coal 1.2
  Bagasse, In Sugar Mill 1.8
  Bituminous Coal 1.1
  Fuel Oil 1.3
  Internal, Mobile ..... Vol. II
  Internal, Stationary 3.0
  Lignite 1.7
  Liquified Petroleum Gas 1.5
  Natural Gas 1.4

Orchard Heater 6.9
Residential Fireplace 1.9
Waste Oil 1.11
Wood Stove 1.10
Concrete
Asphaltic Concrete Plants 8.1
Concrete Batching 8.10
Conical (Teepee) Burners 2.3
Construction Aggregate 8.19
Construction Operations
Fugitive Dust Sources 11.2
Conversion, Coal 8.21
Copper
Primary Smelting 7.3
Secondary Smelting And Alloying 7.9
Cotton
Defoliation And Harvesting 6.16
Ginning 6.3
Dacron
Synthetic Fibers 5.19
Defoliation, Cotton 6.16
Degreasing Solvent 4.6
Dehydrating, Alfalfa 6.1
Diesel Engines, Stationary 3.4
Detergents
Soap And Detergents 5.15
Detonation, Explosives 11.3
Drum
Tank And Drum Cleaning 4.8
Dry Cleaning 4.1
Dual Fuel Engines, Stationary 3.4
Dust
Fugitive Sources 11.2
Dust Loading Sampling Procedures ..... App. D
Dust Loading Analysis ..... App. E
Electric Utility Power Plants, Gas 3.1
Electricity Generators, Stationary Gas Turbine 3.1
Elevators, Feed And Grain Mills 6.4
Explosives 5.6
Explosives Detonation 11.3
Fabric Coating 4.2.2.7
Feed
Beef Cattle Feedlots 6.15
Feed And Grain Mills And Elevators 6.4
Feldspar 8.27
Fermentation 6.5
Fertilizers
Ammonium Nitrate 6.8
Phosphate 6.10
Ferroalloy Production 7.4
Fiber
Glass Fiber Manufacturing 8.11
Fiber, Synthetic 5.19
Fires
Forest Wildfires And Prescribed Burning 11.1
Fireplaces, Residential 1.9

Fish Processing 6.6
Flat Wood Interior Panel Coating 4.2.2.5
Fly Ash
  Clay And Fly Ash Sintering 8.8
Foundries
  Gray Iron Foundries 7.10
  Steel Foundries 7.13
Frit Manufacturing 8.12
Fuel Oil Combustion 1.3
Fugitive Dust Sources 11.2
Furniture Surface Coating, Metal 4.2.2.12

Gas Combustion, Liquified Petroleum 1.5
Gas, Natural
  Natural Gas Combustion 1.4
  Natural Gas Processing 9.2
  Turbines, Electricity-generating 3.1
Gasoline/Diesel Engines 3.3
Ginning, Cotton 6.3
Glass Manufacturing 8.13
Glass Fiber Manufacturing 8.11
Grain
  Feed And Grain Mills And Elevators 6.4
  Harvesting Of Grain 6.17
Gravel
  Sand And Gravel Processing 8.19
Gray Iron Foundries 7.10
Gypsum Manufacturing 8.14

Harvesting
  Cotton 6.16
  Grain 6.17
Heaters, Orchard 6.9
Hydrochloric Acid 5.7
Hydrofluoric Acid 5.8
Highway Vehicles ..... Vol. II

Incineration
  Automobile Body 2.2
  Conical (Teepee) 2.3
  Landfills 2.7
  Medical Waste 2.6
  Open Burning 2.4
  Refuse 2.1
  Sewage Sludge 2.5
Industrial Engines, Gasoline And Diesel 3.3
Industrial Flares 11.5
Industrial Surface Coating 4.2.2
Ink, Printing 5.14
Internal Combustion Engines
  Highway Vehicle ..... Vol. II
  Off-highway Mobile ..... Vol. II
  Off-highway Stationary 3.0
Iron
  Ferroalloy Production 7.4
  Gray Iron Foundries 7.10
  Iron And Steel Mills 7.5
  Taconite Ore Processing 8.22

Label Coating, Pressure Sensitive 4.2.2.9
Landfills 2.7
Large Bore Engines 3.4
Lead
  Ore Crushing And Grinding 7.18
  Miscellaneous Products 7.17
  Primary Lead Smelting 7.6
  Secondary Smelting 7.11
Lead Alkyl 5.22
Lead Oxide And Pigment Production 7.16
Leadbearing Ore Crushing And Grinding 7.18
Lightweight Aggregate Manufacturing 8.25
Lignite Combustion 1.7
Lime Manufacturing 8.15
Liquified Petroleum Gas Combustion 1.5

Magnesium
  Secondary Smelting 7.12
Magnet Wire Coating 4.2.2.3
Magnetic Tape Manufacturing/Surface Coating 4.2.2.13
Maleic Anhydride 5.24
Meat Smokehouses 6.7
Metal Coil Surface Coating 4.2.2.10
Medical Waste Incineration 2.6
Metal Furniture Surface Coating 4.2.2.12
Mineral Wool Manufacturing 8.16
Mobile Sources
  Highway ..... Vol. II
  Off-highway ..... Vol. II

Natural Gas Combustion 1.4
Natural Gas Fired Pipeline Compressors 3.2
Natural Gas Processing 9.2
Nitric Acid Manufacturing 5.9
Nonindustrial Surface Coating 4.2.1
Normal Superphosphates 6.10.1

Off-highway Mobile Sources ..... Vol. II
Off-highway Stationary Sources 3.0
Oil
  Fuel Oil Combustion 1.3
  Waste Oil Combustion 1.11
Open Burning 2.4
Orchard Heaters 6.9
Ore Processing
  Leadbearing Ore Crushing And Grinding 7.18
  Taconite 8.22
Organic Liquid Storage 12.0

Paint And Varnish Manufacturing 5.10
Panel Coating, Wood, Interior 4.2.2.5-1
Paper Coating 4.2.2.6-1
Paved Roads
  Fugitive Dust 11.2
Perlite Manufacturing 8.17
Petroleum
  Liquified Petroleum Gas Combustion 1.5
  Refining 9.1
  Storage Of Organic Liquids 12.0
  Transportation And Marketing Of Petroleum Liquids 4.4

Pharmaceutical Production 5.23
Phosphate Fertilizers 6.10
Phosphate Rock Processing 8.18
Phosphoric Acid 5.11
Phthalic Anhydride 5.12
Pigment
  Lead Oxide And Pigment Production 7.16
Pipeline Compressors, Natural Gas Fired 3.2
Plastic Part Surface Coating, Business Machine 4.2.2.14
Plastics 5.13
Plywood Veneer And Layout Operations 10.3
Poly(ethylene terephthalate) 5.13.2
Polyester Resin Plastics Product Fabrication 4.12
Polypropylene 5.13.1
Polystyrene 5.13.3
Polyvinyl Chloride 5.13.1
Portland Cement Manufacturing 8.6
Prescribed Burning 11.1
Printing Ink 5.14
Pulpboard 10.2
Pulping Chemical Wood 10.1

Reclamation, Waste Solvent 4.7
Recovery, Sulfur 5.18
Refractories, Castable 8.5
Residential Fireplaces 1.9
Roads, Paved
  Fugitive Dust 11.2
Roads, Unpaved
  Fugitive Dust 11.2
Roasting Coffee 6.2
Rock
  Phosphate Rock Processing 8.18
Roofing, Asphalt 8.2
Rubber, Synthetic 5.20
Sampling Procedures, Surface And Bulk Materials ..... App. D
Sand And Gravel Processing 8.19
Sewage Sludge Incineration 2.5
Sintering, Clay And Fly Ash 8.8
Smelting
  Primary Copper Smelting 7.3
  Primary Lead Smelting 7.6
  Secondary Copper Smelting And Alloying 7.9
  Secondary Lead Smelting 7.11
  Secondary Magnesium Smelting 7.12
  Zinc Smelting 7.7
Smokehouses, Meat 6.7
Soap And Detergent Manufacturing 5.15
Sodium Carbonate Manufacturing 5.16
Solvent
  Commercial/Consumer Use 4.10
  Degreasing 4.6
  Waste Reclamation 4.7
Starch Manufacturing 6.11
Stationary Gas Turbines 3.1
Stationary Sources, Off-highway 3.0
Steel
  Iron And Steel Mills 7.5

Foundries 7.13
Storage Battery Production 7.15
Storage Of Organic Liquids 12.0
Sugar Cane Processing 6.12
Sugar Mills, Bagasse Combustion In 1.8
Sulfur Recovery 5.18
Sulfuric Acid 5.17
Surface Coating 4.2
Surface Material Analysis Procedures ..... App. E
Surface Material Sampling Procedures ..... App. D
Synthetic Ammonia 5.2
Synthetic Fiber 5.19
Synthetic Rubber 5.20

Taconite Ore Processing 8.22
Tank And Drum Cleaning 4.8
Tape, Magnetic, Manufacturing 4.2.2.13
Tape Coating, Pressure Sensitive 4.2.2.9
Teepee (Conical) Burners 2.3
Terephthalic Acid 5.21
Tilling, Agricultural
Fugitive Dust 11.2
Transportation And Marketing Of Petroleum Liquids 4.4
Triple Superphosphates 6.10.2
Truck Surface Coating, Light Duty 4.2.2.8
Turbines, Natural Gas Fired 3.1

Unpaved Roads
Fugitive Dust 11.2
Urea 6.14

Varnish
Paint And Varnish Manufacturing 5.10
Vehicles, Highway And Off-highway ..... Vol. II

Waste Solvent Reclamation 4.7
Waste Oil Combustion 1.11
Waste Water Collection, Treatment and Storage 4.13
Wet Cooling Towers 11.4
Whiskey Production
Fermentation 6.5
Wildfires, Forest 11.1
Wine Making
Fermentation 6.5
Wire Coating, Magnet 4.2.2.3
Wood
Pulping, Chemical 10.1
Stoves 1.10
Waste Combustion In Boilers 1.6
Interior Panel Coating ..... 4 .2.2.5
Woodworking Waste Collection Operations 10.4

Zinc
Secondary Processing 7.14
Smelting 7.7

1.1 BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

1.1.1 General

Coal is a complex combination of organic matter and inorganic ash formed over eons from successive layers of fallen vegetation. Coal types are broadly classified as anthracite, bituminous, subbituminous, or lignite. These classifications are based on coal heating value together with relative amounts of fixed carbon, volatile matter, ash, sulfur, and moisture. Formulae and tables for classifying coals are given in Reference 1. See AP-42 Sections 1.2 and 1.7 for discussions of anthracite and lignite combustion, respectively.

There are three major coal combustion techniques: suspension firing, grate firing, and fluidized bed combustion. Suspension firing is the primary combustion mechanism in pulverized coal and cyclone systems. Grate firing is the primary mechanism in underfeed and overfeed stokers. Both mechanisms are employed in spreader stokers. Fluidized bed combustion, while not constituting a significant percentage of the total boiler population, has nonetheless gained popularity in the last decade and today generates steam for industries, cogenerators, independent power producers, and utilities.

Pulverized coal furnaces are used primarily in utility and large industrial boilers. In these systems, the coal is pulverized in a mill to the consistency of talcum powder (i.e., at least 70 percent of the particles will pass through a 200 mesh sieve). The pulverized coal is generally entrained in primary air before being fed through burners to the furnace, where it is fired in suspension. Pulverized coal furnaces are classified as either dry or wet bottom, depending on the ash removal technique. Dry bottom furnaces fire coals with high ash fusion temperatures and use dry ash removal techniques. In wet bottom (or slag tap) furnaces, coals with low ash fusion temperatures are combusted and molten ash is drained from the bottom of the furnace. Pulverized coal furnaces are further classified by the firing position of the burners, i.e., single (front or rear) wall, horizontally opposed, vertical, tangential (or corner-fired). Wall-fired boilers can be either single wall-fired (with burners on only one wall of the furnace firing horizontally) or opposed wall-fired (with burners mounted on two opposing walls). Tangentially-fired boilers have burners mounted in the corners of the furnace. The fuel and air are injected toward the center of the furnace to create a vortex that enhances air and fuel mixing.

Cyclone furnaces burn low ash fusion temperature coal which has been crushed to below 4 mesh particle size. The coal is fed tangentially in a stream of primary air to a horizontal cylindrical furnace. Within the furnace, small coal particles are burned in suspension while larger particles are forced against the outer wall. Because of the high temperatures developed in the relatively small furnace volume, and because of the low fusion temperature of the coal ash, much of the ash forms a liquid slag on the furnace walls. The slag drains from the walls to the bottom of the furnace where it is removed through a slag tap opening. Cyclone furnaces are used mostly in utility and large industrial applications.

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. Because of significant carbon content in the particulate, fly ash reinjection from mechanical collectors is commonly employed to improve boiler efficiency. Ash residue from the fuel bed is deposited in a receiving pit at the end of the grate.

In overfeed stokers, coal is fed onto a traveling or vibrating grate and burns on the fuel bed as it progresses through the furnace. Ash particles fall into an ash pit at the rear of the stoker. The term "overfeed" applies because the coal is fed onto the moving grate under an adjustable gate. Conversely,

in "underfeed" stokers, coal is fed into the firing zone from below by mechanical rams or screw conveyors. The coal moves in a channel, known as a retort, from which it is forced upward, spilling over the top of each side to form and to feed the fuel bed. Combustion is completed by the time the bed reaches the side dump grates, from which the ash is discharged into shallow pits. Underfeed stokers include single retort units and multiple retort units, the latter having several retorts side by side.

Small hand-fired boilers and furnaces are sometimes found in small industrial, commercial, institutional, or residential applications. In most hand-fired units, the fuel is primarily burned in layers on the bottom of the furnace or on a grate. From an emissions standpoint, hand-fired units generally have higher carbon monoxide (CO) and volatile organic compounds (VOC) emissions than larger boilers because of their lower combustion efficiencies.

In a fluidized bed combustor (FBC), the coal is introduced to a bed of either sorbent (limestone or dolomite) or inert material (usually sand) which is fluidized by an upward flow of air. Most of the combustion occurs within the bed, but some smaller particles burn above the bed in the "freeboard" space. The two principal types of atmospheric FBC boilers are bubbling bed and circulating bed. The fundamental distinguishing feature between these types is the fluidization velocity. In the bubbling bed design, the fluidization velocity is relatively low, ranging between 1.5 and 4 m/sec (5 and 12 ft/sec), in order to minimize solids carryover or elutriation from the combustor. Circulating FBCs, however, employ fluidization velocities as high as 9 m/sec (30 ft/sec) to promote the carryover or circulation of solids. High temperature cyclones are used in circulating FBCs and in some bubbling FBCs to capture the solid fuel and bed material for return to the primary combustion chamber. The circulating FBC maintains a continuous, high-volume recycle rate which increases the fuel residence time compared to the bubbling bed design. Because of this feature, circulating FBCs often achieve higher combustion efficiency and better sorbent utilization than bubbling bed units.[3]

1.1.2 Emissions and Controls

The major pollutants of concern from bituminous and subbituminous coal combustion are particulate matter (PM), sulfur oxides (SO_x), and nitrogen oxides (NO_x). Emissions from coal combustion 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. Some unburnt combustibles, including numerous organic compounds and CO, are generally emitted even under proper boiler operating conditions. Emission factors for major and minor pollutants are given in Tables 1.1-1 through 1.1-14.

Particulate Matter[2-5] - Particulate matter 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 emitted particulate is largely comprised of inorganic ash residues. In wet bottom pulverized coal units and cyclones, the quantity of ash leaving the boiler is lower than in dry bottom units, because some of the ash liquifies, collects on the furnace walls, and drains from the furnace bottom as molten slag. Particulate emission limits specified in applicable New Source Performance Standards (NSPS) are summarized in Table 1.1-15.

Because a mixture of fine and coarse coal particles is fired in spreader stokers, significant unburnt carbon can be present in the particulate. To improve boiler efficiency, fly ash from collection devices (typically multiple cyclones) is sometimes reinjected into spreader stoker furnaces. This practice can dramatically increase the particulate loading at the boiler outlet and, to a lesser extent, at the mechanical collector outlet. Fly ash can also be reinjected from the boiler, air heater, and economizer dust hoppers. Fly ash reinjection from these hoppers increases particulate loadings less

than from multiple cyclones.

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. Fly ash reinjection is not practiced in these kinds of stokers.

Variables other than firing configuration and fly ash reinjection can affect PM emissions from stokers. Particulate loadings will often increase as load increases (especially as full load is approached) and with sudden load changes. Similarly, particulate can increase as the coal ash and "fines" contents increase. Fines, in this context, are coal particles smaller than about 1.6 millimeters (1/16 inch) in diameter. Conversely, particulate can be reduced significantly when overfire air pressures are increased.

FBCs may tax conventional particulate control systems. The particulate mass concentration exiting FBCs is typically 2 to 4 times higher than that from pulverized coal boilers[13]. Fluidized bed combustor particles are also, on average, smaller in size, irregularly shaped, and have higher surface area and porosity relative to pulverized coal ashes. Fluidized bed combustion ash is more difficult to collect in electrostatic precipitators (ESPs) than pulverized coal ash because FBC ash has a higher electrical resistivity. In addition, the use of multiclones for fly ash recycling, inherent with FBC processes, tends to reduce flue gas stream particulate size[13].

The primary kinds of PM control devices used for coal combustion include multiple cyclones, ESPs, fabric filters (or baghouses), and scrubbers. Some measure of control will even result from fly ash settling in boiler/air heater/economizer dust hoppers, large breeching, and chimney bases. The effects of such settling are reflected in current emission factors.

ESPs are the most common high-efficiency PM control device used on pulverized coal and cyclone units; they are also being used increasingly on stokers. Generally, ESP collection efficiencies are a function of collection plate area per unit volumetric flow rate of flue gas through the device. Particulate control efficiencies of 99.9 percent or above are obtainable with ESPs. Electrostatic precipitators located downstream of air preheaters (i.e., cold side precipitators) operate at significantly reduced efficiencies when low sulfur coal is fired. Fabric filters have recently seen increased use in both utility and industrial applications, generally achieving at least 99.8 percent efficiency. An advantage of fabric filters is that they are unaffected by the high fly ash resistivities associated with low sulfur coals. Scrubbers are also used to control particulate, although their primary use is to control sulfur oxides. One drawback of scrubbers is the high energy usage required to achieve control efficiencies comparable to those for ESPs and baghouses[2].

Mechanical collectors, generally multiple cyclones, are the primary means of PM control on many stokers. They are sometimes installed upstream of high-efficiency control devices in order to reduce the ash collection burden on these devices. Cyclones are also an integral part of most FBC designs. Depending on application and design, multiple cyclone efficiencies can vary widely. Where cyclone design flow rates are not attained (which is common with underfeed and overfeed stokers), these devices may be only marginally effective and may prove little better in reducing particulate than a large breeching. Conversely, well-designed multiple cyclones, operating at the required flow rates, can achieve collection efficiencies on spreader stokers and overfeed stokers of 90 to 95 percent. Even higher collection efficiencies are obtainable on spreader stokers with reinjected fly ash because of the larger particle sizes and increased particulate loading reaching the controls[5-6].

Sulfur Oxides[7-9] - Gaseous sulfur oxides (SO_x) from coal combustion are primarily sulfur dioxide (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 is 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. In general, boiler size, firing configuration and boiler operations have little effect on the percent conversion of fuel sulfur to SO_x. Sulfur dioxide emission limits specified in applicable NSPS are summarized in Table 1.1-15.

Several techniques are used to reduce SO_x emissions from coal combustion. One way is to switch to lower sulfur coals, since SO_x 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.

Many flue gas desulfurization (FGD) techniques can remove SO_2 formed during combustion. Flue gases can be treated using wet, dry, or semi-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 greater than 90 percent of the incoming SO_2. Particulate reduction of up to 99 percent is also possible with wet scrubbers, but fly ash is often collected by upstream ESPs or baghouses, to avoid erosion of the desulfurization equipment and possible interference with FGD process reactions[7]. Also, the volume of scrubber sludge is reduced with separate fly ash removal and contamination of the reagents and byproducts is prevented. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbing are among the commercially proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also operating variables. A summary table of commercial post-combustion SO_2 controls is provided in Table 1.1-16.

A number of dry and wet sorbent injection technologies are under development to capture SO_2 in the furnace, the heat transfer sections, or ductwork downstream of the boiler. These technologies are generally designed for retrofit applications and are well-suited for coal combustion sources requiring moderate SO_2 reduction and which have a short remaining life.

Nitrogen Oxides[10-11] - Nitrogen oxides (NO_x) emissions from coal combustion are primarily nitrogen oxide (NO), with only a few volume percent as nitrogen dioxide (NO_2). Nitrous oxide (N_2O) is also emitted at ppm levels. Nitrogen oxides formation results from thermal fixation of atmospheric nitrogen in the combustion flame and from oxidation of nitrogen bound in the coal. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to N_2 concentration in the flame, the square root of oxygen (O_2) concentration in the flame, and the gas residence time[22]. Typically, only 20 to 60 percent of the fuel nitrogen is converted to NO_x. Bituminous and subbituminous coals usually contain from 0.5 to 2 weight percent nitrogen, mainly present in aromatic ring structures. Fuel nitrogen can account for up to 80 percent of total NO_x from coal combustion. Nitrogen oxide emission limits in applicable NSPS are summarized in Table 1.1-15.

A number of combustion modifications have been used to reduce NO_x emissions from boilers. A summary of currently utilized NO_x control technology for stokers is given in Table 1.1-17. Low excess air (LEA) firing is the most widespread combustion modification, because it can be practiced in

both old and new units and in all sizes of boilers. Low excess air firing is easy to implement and has the added advantage of increasing fuel use efficiency. Low excess air firing is generally effective only above 20 percent excess air for pulverized coal units and above 30 percent excess air for stokers. Below these levels, the NO_x reduction from decreased O_2 availability is offset by increased NO_x production due to higher flame temperatures. Another NO_x reduction technique is simply to switch to a coal having a lower nitrogen content, although many boilers may not properly fire coals with different properties.

Off-stoichiometric (or staged) combustion is also an effective means of controlling NO_x emissions from coal-fired equipment. This can be achieved by using overfire air or low-NO_x burners designed to stage combustion in the flame zone. Other NO_x reduction techniques include flue gas recirculation, load reduction, and steam or water injection. However, these techniques are not very effective for use on coal-fired equipment because of the fuel nitrogen effect. Ammonia injection is a post-combustion technique which can also be used, but it is costly relative to other methods. For cyclone boilers, the use of natural gas reburning for NO_x emission control is under investigation on a full-scale utility boiler.[33] The net reduction of NO_x from any of these techniques or combinations thereof varies considerably with boiler type, coal properties, and boiler operating practices. Typical reductions will range from 10 to 60 percent. References 10 and 27 may be consulted for detailed discussion of each of these NO_x reduction techniques. To date, flue gas treatment has not been used commercially to reduce NO_x emissions from coal-fired boilers because of its higher relative cost.

Carbon Monoxide - The rate of CO emissions from combustion sources depends on the fuel oxidation efficiency of the source. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or not well maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces ten to emit more CO and organics than larger combustors. This is because smaller units usually have less high-temperature residence time and, therefore, less time to achieve complete combustion than larger combustors. Various combustion modification techniques used to reduce NO_x can produce increased CO emissions.

Organic Compounds - Small amounts of organic compounds are emitted from coal combustion. As with CO emissions, the rate at which organic compounds are emitted depends on the combustion efficiency of the boiler. Therefore, any combustion modification which reduces the combustion efficiency will most likely increase the concentrations of organic compounds in the flue gases.

Total organic compounds (TOC) include volatile organic compounds (VOCs), semi-volatile organic compounds, and condensible organic compounds. Emissions of VOCs are primarily characterized by the criteria pollutant class of unburned vapor-phase hydrocarbons. Unburned hydrocarbon emissions can include essentially all vapor phase organic compounds emitted from a combustion source. These are primarily emissions of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in the vapor phase at flue gas temperatures. These emissions include alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene.)[17,18].

The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called polynuclear aromatic hydrocarbons (PNA or PAH). There are also PAH-nitrogen analogs. Polycyclic organic matter can be especially prevalent in the emissions from coal combustion, because a large fraction of the volatile matter in coal exits as POM[19].

Formaldehyde is formed and emitted during combustion of hydrocarbon-based fuels such as coal. Formaldehyde is present in the vapor phase of the flue gas. Formaldehyde is subject to oxidation and decomposition at the high temperatures encountered during combustion Thus, larger units with efficient combustion (resulting from closely regulated air-fuel ratios, uniformly high combustion chamber temperatures, and relatively long gas residence times) have lower formaldehyde emission rates than do smaller, less efficient combustion units[20,21].

Trace elements - Trace elements are also emitted from the combustion of coal. For this update of AP-41, trace metals included in the list of 189 hazardous air pollutants under Title III od the 1990 Clean Air Act Amendments[23] were considered. The quantity of trace metals depends on combustion temperature, fuel feed mechanism, and the composition of the fuel. The temperature determines the degree of volatilization of specific trace elements contained in the fuel. The fuel feed mechanism affects the partitioning of elements between bottom ash and fly ash. The quantity of any given metal emitted, in general, depends on:

- the physical and chemical properties of the element itself;
- its concentration in the fuel;
- the combustion conditions; and
- the type of particulate control device used, and its collection efficiency as a function of particle size.

It has become widely recognized that some trace metals become concentrated in certain waste particle streams from a combustor (e.g., bottom ash, collector ash, and flue gas particulate) while others do not[19]. Various classification schemes have been developed to describe this partitioning behavior.[24-26] The classification scheme used by Baig, et al.[26] is as follows:

- Class 1: Elements which are approximately equally distributed between fly ash and bottom ash, or show little or no small particle enrichment.
- Class 2: Elements which are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size.
- Class 3: Elements which are intermediate between Class 1 and 2.
- Class 4: Elements which are emitted in the gas phase.

Fugitive Emissions - Fugitive emissions are defined as pollutants which escape from an industrial process due to leakage, materials handling, inadequate operational control, transfer or storage. The fly ash handling operations in most modern utility and industrial combustion sources consist of pneumatic systems or enclosed and hooded systems which are vented through small fabric filters or other dust control devices. The fugitive PM emissions from these systems are therefore minimal. Fugitive particulate emissions can sometimes occur during fly ash transfer operations from silos to trucks or rail cars.

Emission factors for SO_x, NO_x, and CO are presented in Tables 1.1-1 and 1.1-2, along with emission factor ratings. Particulate matter and PM-10 emission factors and ratings are given in Tables 1.1-3 and 1.1-4. Cumulative particle size distribution and particulate size specific emission factors are given in Figures 1.1-1 through 1.1-6 and Tables 1.1-5 through 1.1-10, respectively. Emission factors

and ratings for speciated organics and N_2O are given in Tables 1.1-11 and 1.1-12. Emission factors and ratings for other non-criteria pollutants and lead are listed in Tables 1.1-13 and 1.1-14.

In general, the baseline emissions of criteria and non- criteria pollutants are those from uncontrolled combustion sources. Uncontrolled sources are those without add-on pollution control (APC) equipment, low-NO_x burners, or other modifications designed for emission control. Baseline emission for SO_2 and PM can also be obtained from measurements taken upstream of APC equipment.

Because of the inherently low NO_x emission characteristics of FBCs and the potential for in-bed SO_2 capture by calcium-based sorbents, uncontrolled emission factors for this source category were not developed in the same sense as with the other source categories. For NO_x emissions, the data collected from test reports were considered to be baseline if no additional add-on NO_x control system (such as ammonia injection) was operated. For SO_2 emissions, a correlation was developed from reported data on FBCs to relate SO_2 emissions to the coal sulfur content and the calcium-to-sulfur ratio in the bed.

TABLE 1.1-1. (ENGLISH UNITS) EMISSION FACTORS FOR SULFUR OXIDES (SO_x),NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	SCC	SO_x[b]		NO_x[c]		CO[d,e]	
		Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating
Pulverized coal fired, dry bottom, wall fired	101002-02/22 102002-02/22 103002-06/22	38S (35S)	A	21.7	A	0.5	A
Pulverized coal fired, dry bottom, tangentially fired	101002-12/26 102002-12/26 103002-16/26	38S (35S)	A	14.4	A	0.5	A
Pulverized coal fired, wet bottom	101002-12/21 102002-01/21 103002-05/21	38S (35S)	D	34.0	C	0.5	A
Cyclone furnace	101002-03/23 102002-03/23 103002-23/01	38S (35S)	D	33.8	C	0.5	A
Spreader stoker	101002-04/24 102002-04/24 103002-09/24	38S (35S)	B	13.7	A	5	A
Spreader stoker, with multiple cyclones, and reinjection	101002-03/24 101002-04/24 103002-09/24	38S (35S)	B	13.7	A	5	A
Spreader stoker, with multiple cyclones, no reinjection	101002-04/24 101002-04/24 103002-09/24	38S (35S)	A	13.7	A	5	A
Overfeed stoker[f]	101002-05/25 102002-05/10/25 103002-07/25	38S (35S)	B	7.5	A	6	B
Overfeed stoker, with multiple cyclones[f]	101002-05/25 102002-05/10/25 103-002-07/25	38S (35S)	B	7.5	A	6	B
Underfeed stoker	102002-06 103002-08	31S	B	9.5	A	11	B
Underfeed stoker, with multiple cyclone	102002-06 103002-08	31S	B	9.5	A	11	B
Hand-fed units	103002-14	31S	D	9.1	E	275	E
Fluidized bed combustor, circulating bed	101002-17 102002-17 103002-17	g	E	3.9	E	18	E
Fluidized bed combustor, bubbling bed	101002-17 102002-17 103002-17	g	E	15.2	D	18	D

a. Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired.

b. Expressed as SO_2, including SO_2, SO_3, and gaseous sulfates. Factors in parentheses should be used to estimate gaseous SO_x emissions for subbituminous coal. In all cases, S is weight % sulfur content of coal as fired. Emission factor would be calculated by multiplying the weight

percent sulfur in the coal by the numerical value preceding S. On average for bituminous coal, 95% of fuel sulfur is emitted as SO_2, and only about 0.7% of fuel sulfur is emitted as SO_3 and gaseous sulfate. An equally small percent of fuel sulfur is emitted as particulate sulfate (References 9, 13). Small quantities of sulfur are also retained in bottom ash. With subbituminous coal, about 10% more fuel sulfur is retained in the bottom ash and particulate because of the more alkaline nature of the coal ash. Conversion to gaseous sulfate appears about the same as for bituminous coal.

c. Expressed as NO_2. Generally, 95+ volume % of nitrogen oxides present in combustion exhaust will be in the form of NO, the rest NO_2 (Reference 11). To express factors as NO, multiply factors by 0.66. All factors represent emission at baseline operation (i.e., 60 to 110% load and no NO_x control measures).

d. Nominal values achievable under normal operating conditions. Values are one or two orders of magnitude higher can occur when combustion is not complete.

e. Emission factors for CO_2 emissions from coal combustion should be calculated using CO_2/ton coal = 73.3C, where C is the weight percent carbon content of the coal.

f. Includes traveling grate, vibrating grate and chain grate stokers.

g. Sulfur dioxide emission factors for fluidized bed combustion are a function of fuel sulfur content and calcium-to-sulfur ratio. For both bubbling bed and circulating bed design, use: lb SO_2/ton coal = $39.6(S)(Ca/S)^{-1.9}$. In this equation, S is the weight percent sulfur in the fuel and Ca/S is the molar calcium-to-sulfur ratio in the bed. This equation may be used when the Ca/S is between 1.5 and 7. When no calcium-based sorbents are used and the bed material is inert with respect to sulfur capture, the emission factor for underfeed stokers should be used to estimate the FBC SO_2 emissions. In this case, the emission factor ratings are E for both bubbling and circulating units.

SCC = Source classification code.

TABLE 1.1-2. (METRIC UNITS) EMISSION FACTORS FOR SULFUR OXIDES (SO_x),NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	SCC	SO_x[b]		NO_x[c]		CO[d,e]	
		Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating
Pulverized coal fired, dry bottom, wall fired	101002-02/22 102002-02/22 103002-06/22	19S (17.5S)	A	10.85	A	.25	A
Pulverized coal fired, dry bottom, tangentially fired	101002-12/26 102002-12/26 103002-16/26	19S (17.5S)	A	7.2	A	.25	A
Pulverized coal fired, wet bottom	101002-12/21 102002-01/21 103002-05/21	19S (17.5S)	D	17	C	.25	A
Cyclone furnace	101002-03/23 102002-03/23 103002-23/01	19S (17.5S)	D	16.9	C	.25	A
Spreader stoker	101002-04/24 102002-04/24 103002-09/24	19S (17.5S)	B	6.85	A	2.5	A
Spreader stoker, with multiple cyclones, and reinjection	101002-03/24 101002-04/24 103002-09/24	19S (17.5S)	B	6.85	A	2.5	A
Spreader stoker, with multiple cyclones, no reinjection	101002-04/24 101002-04/24 103002-09/24	19S (17.5S)	A	6.85	A	2.5	A
Overfeed stoker[f]	101002-05/25 102002-05/10/25 103002-07/25	19S (17.5S)	B	3.75	A	3	B
Overfeed stoker, with multiple cyclones[f]	101002-05/25 102002-05/10/25 103-002/07/25	19S (17.5S)	B	3.75	A	3	B
Underfeed stoker	102002-06 103002-08	15.5S	B	4.75	A	5.5	B
Underfeed stoker, with multiple cyclone	102002-06 103002-08	15.5S	B	4.75	A	5.5	B
Hand-fed units	103002-14	15.5S	D	4.55	E	137.5	E
Fluidized bed combustor, circulating bed	101002-17 102002-17 103002-17	g	E	1.95	E	9	E
Fluidized bed combustor, bubbling bed	101002-17 102002-17 103002-17	g	E	7.6	D	9	D

a. Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired.

b. Expressed as SO_2, including SO_2, SO_3, and gaseous sulfates. Factors in parentheses should be used to estimate gaseous SO_x emissions for subbituminous coal. In all cases, S is weight

% sulfur content of coal as fired. Emission factor would be calculated by multiplying the weight percent sulfur in the coal by the numerical value preceding S. On average for bituminous coal, 95% of fuel sulfur is emitted as SO_2, and only about 0.7% of fuel sulfur is emitted as SO_3 and gaseous sulfate. An equally small percent of fuel sulfur is emitted as particulate sulfate (References 9, 13). Small quantities of sulfur are also retained in bottom ash. With subbituminous coal, about 10% more fuel sulfur is retained in the bottom ash and particulate because of the more alkaline nature of the coal ash. Conversion to gaseous sulfate appears about the same as for bituminous coal.

c. Expressed as NO_2. Generally, 95+ volume % of nitrogen oxides present in combustion exhaust will be in the form of NO, the rest NO_2 (Reference 11). To express factors as NO, multiply factors by 0.66. All factors represent emission at baseline operation (i.e., 60 to 110% load and no NO_x control measures).

d. Nominal values achievable under normal operating conditions. Values are one or two orders of magnitude higher can occur when combustion is not complete.

e. Emission factors for CO_2 emissions from coal combustion should be calculated using CO_2/Mg coal = 36.7C, where C is the weight percent carbon content of the coal.

f. Includes traveling grate, vibrating grate and chain grate stokers.

g. Sulfur dioxide emission factors for fluidized bed combustion are a function of fuel sulfur content and calcium-to-sulfur ratio. For both bubbling bed and circulating bed design, use: kg SO_2/Mg coal = $19.8(S)(Ca/S)^{-1.9}$. In this equation, S is the weight percent sulfur in the fuel and Ca/S is the molar calcium-to-sulfur ratio in the bed. This equation may be used when the Ca/S is between 1.5 and 7. When no calcium-based sorbents are used and the bed material is inert with respect to sulfur capture, the emission factor for underfeed stokers should be used to estimate the FBC SO_2 emissions. In this case, the emission factor ratings are E for both bubbling and circulating units.

SCC = Source classification code.

TABLE 1.1-3. (ENGLISH UNITS) EMISSION FACTORS FOR PARTICULATE MATTER (PM) AND PM LESS THAN 10 MICRONS (PM-10) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	SCC	Filterable PM[b]		PM-10	
		Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating
Pulverized coal fired, dry bottom, wall fired	101002-02/22 102002-02/22 103002-06/22	10A	A	2.3A	E
Pulverized coal fired, dry bottom, tangentially fired	101002-12/26 102002-12/26 103002-16/26	10A	B	2.3A[c]	E
Pulverized coal fired, wet bottom	101002-12/21 102002-01/21 103002-05/21	7A[d]	D	2.6A	E
Cyclone furnace	101002-03/23 102002-03/23 103002-23/01	2A[d]	E	0.26A	E
Spreader stoker	101002-04/24 102002-04/24 103002-09/24	66[e]	B	13.2	E
Spreader stoker, with multiple cyclones, and reinjection	101002-03/24 101002-04/24 103002-09/24	17	B	12.4	E
Spreader stoker, with multiple cyclones, no reinjection	101002-04/24 101002-04/24 103002-09/24	12	A	7.8	E
Overfeed stoker[f]	101002-05/25 102002-05/10/25 103002-07/25	16[g]	C	6.0	E
Overfeed stoker, with multiple cyclones[f]	101002-05/25 102002-05/10/25 103002-07/25	16[h]	C	5.0	E
Underfeed stoker	102002-06 103002-08	15[i]	D	6.2	E
Underfeed stoker, with multiple cyclone	102002-06 103002-08	11[h]	D	6.2[j]	E
Hand-fed units	103002-14	15	E	6.2[j]	E
Fluidized bed combustor, bubbling bed	101002-17 102002-17 103002-17	12	E	13.2[k]	E
Fluidized bed combustor, circulating bed	101002-17 102002-17 103002-17	17	E	13.2	E

a. Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired.

b. Based on EPA Method 5 (front half catch) as described in Reference 28. Where particulate is expressed in terms of coal ash content, A, factor is determined by multiplying weight % ash content of coal (as fired) by the numerical value preceding the A. For example, if coal with 8%

ash is fired in a pulverized coal fired, dry bottom unit, the PM emission factor would be 10 x 8, or 80 lb/ton. The "condensible" matter collected in back half catch of EPA Method 5 averages <5% of front half, or "filterable", catch for pulverized coal and cyclone furnaces; 10% for spreader stokers; 15% for other stokers; and 50% for handfired units (References 6, 29, 30).

c. No data found; use assume emission factor for pulverized coal-fired dry bottom boilers.

d. Uncontrolled particulate emissions, when no fly ash reinjection is employed. When control device is installed, and collected fly ash is reinjected to boiler, particulate from boiler reaching control equipment can increase up to a factor of two.

e. Accounts for fly ash settling in an economizer, air heater or breaching upstream of control device or stack. (Particulate directly at boiler outlet typically will be twice this level.) Factor should be applied even when fly ash is reinjected to boiler from air heater or economizer dust hoppers.

f. Includes traveling grate, vibrating grate and chain grate stokers.

g. Accounts for fly ash settling in breaching or stack base. Particulate loadings directly at boiler outlet typically can be 50% higher.

h. See Reference 34 for discussion of apparently low multiple cyclone control efficiencies, regarding uncontrolled emissions.

i. Accounts for fly ash settling in breaching downstream of boiler outlet.

j. No data found; use emission factor for underfeed stoker.

k. No data found; use emission factor for spreader stoker.

SCC = Source classification code.

TABLE 1.1-4. (METRIC UNITS) EMISSION FACTORS FOR PARTICULATE MATTER (PM) AND PM LESS THAN 10 MICRONS (PM-10) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	SCC	Fitlerable PM[b]		PM-10	
		Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating
Pulverized coal fired, dry bottom, wall fired	101002-02/22 102002-02/22 103002-06/22	5A	A	1.15A	E
Pulverized coal fired, dry bottom, tangentially fired	101002-12/26 102002-12/26 103002-16/26	5A	B	1.15A[c]	E
Pulverized coal fired, wet bottom	101002-12/21 102002-01/21 103002-05/21	3.5A[d]	D	1.3A	E
Cyclone furnace	101002-03/23 102002-03/23 103002-23/01	1A[d]	E	0.13A	E
Spreader stoker	101002-04/24 102002-04/24 103002-09/24	33[e]	B	6.6	E
Spreader stoker, with multiple cyclones, and reinjection	101002-03/24 101002-04/24 103002-09/24	8.5	B	6.6	E
Spreader stoker, with multiple cyclones, no reinjection	101002-04/24 101002-04/24 103002-09/24	6	A	3.9	E
Overfeed stoker[f]	101002-05/25 102002-05/10/25 103002-07/25	8[g]	C	3.0	E
Overfeed stoker, with multiple cyclones[f]	101002-05/25 102002-05/10/25 103-002-07/25	4.5[h]	C	2.5	E
Underfeed stoker	102002-06 103002-08	7.5[i]	D	3.1	E
Underfeed stoker, with multiple cyclone	102002-06 103002-08	5.5[h]	D	3.1[i]	E
Hand-fed units	103002-14	7.5	E	3.1[i]	E
Fluidized bed combustor, bubbling bed	101002-17 102002-17 103002-17	6	E	6.6[k]	E
Fluidized bed combustor, circulating bed	101002-17 102002-17 103002-17	8.5	E	6.6	E

a. Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired.

b. Based on EPA Method 5 (front half catch) as described in Reference 28. Where particulate is expressed in terms of coal ash content, A, factor is determined by multiplying weight % ash content of coal (as fired) by the numerical value preceding the A. For example, if coal with 8%

ash is fired in a pulverized coal fired, dry bottom unit, the PM emission factor would be 5 x 8, or 40 kg/Mg. The "condensible" matter collected in back half catch of EPA Method 5 averages <5% of front half, or "filterable", catch for pulverized coal and cyclone furnaces; 10% for spreader stokers; 15% for other stokers; and 50% for handfired units (References 6, 29, 30).

c. No data found; use assume emission factor for pulverized coal-fired dry bottom boilers.

d. Uncontrolled particulate emissions, when no fly ash reinjection is employed. When control device is installed, and collected fly ash is reinjected to boiler, particulate from boiler reaching control equipment can increase up to a factor of two.

e. Accounts for fly ash settling in an economizer, air heater or breaching upstream of control device or stack. (Particulate directly at boiler outlet typically will be twice this level.) Factor should be applied even when fly ash is reinjected to boiler from air heater or economizer dust hoppers.

f. Includes traveling grate, vibrating grate and chain grate stokers.

g. Accounts for fly ash settling in breaching or stack base. Particulate loadings directly at boiler outlet typically can be 50% higher.

h. See Reference 34 for discussion of apparently low multiple cyclone control efficiencies, regarding uncontrolled emissions.

i. Accounts for fly ash settling in breaching downstream of boiler outlet.

j. No data found; use emission factor for underfeed stoker.

k. No data found; use emission factor for spreader stoker.

SCC = Source classification code.

TABLE 1.1-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR DRY BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS COAL[a]

Particle Size[b] (μm)	Cumulative Mass % ≤ stated size					Cumulative Emission Factor[c] [kg/Mg (lb/ton) coal, as fired]									
		Controlled				Uncontrolled		Controlled[d]							
								Multiple cyclones		Scrubber		ESP		Baghouse	
	Uncontrolled	Multiple cyclones	Scrubber	ESP	Baghouse	Factor	Rating	Factor	Rating	Factor	Rating	Factor	Rating	Factor	Rating
15	32	54	81	79	97	1.6A (3.2A)	C	0.54A (1.08A)	E	0.24A (0.48A)	D	0.032A (0.06A)	D	0.010A (0.02A)	E
10	23	29	71	67	92	1.15A (2.3A)	C	0.29A (0.58A)	E	0.21A (0.42A)	D	0.027A (0.05A)	D	0.009A (0.02A)	E
6	17	14	62	50	77	0.85A (1.7A)	C	0.14A (0.28A)	E	0.19A (0.38A)	D	0.020A (0.04A)	D	0.008A (0.02A)	E
2.5	6	3	51	29	53	0.3A (0.6A)	C	0.03A (0.06A)	E	0.15A (0.3A)	D	0.012A (0.02A)	D	0.005A (0.01A)	E
1.25	2	1	35	17	31	0.10A (0.2A)	C	0.01A (0.02A)	E	0.11A (0.22A)	D	0.007A (0.01A)	D	0.003A (0.006A)	E
1.00	2	1	31	14	25	0.10A (0.2A)	C	0.01A (0.02A)	E	0.09A (0.18A)	D	0.006A (0.01A)	D	0.003A (0.006A)	E
0.625	1	1	20	12	14	0.05A (0.10A)	C	0.01A (0.02A)	E	0.06A (0.12A)	D	0.005A (0.01A)	D	0.001A (0.002A)	E
TOTAL	100	100	100	100	100	5A (10A)	C	1A (2A)	E	0.3A (0.6A)	D	0.04A (0.08A)	D	0.01A (0.02A)	E

a. Reference 32. Applicable SCCs are 101002-02/22, 102002-02/22, 103002-06/22, 101002-12/26, 102002-12/26, and 103002-16/26.
b. Expressed as aerodynamic equivalent diameter.
c. A = coal ash weight %, as fired.
d. Estimated control efficiency for multiple cyclones is 80%; for scrubber, 94%; for ESP, 99.2%; and for baghouse, 99.8%.

ESP = Electrostatic precipitator.
SCC = Source classification code.

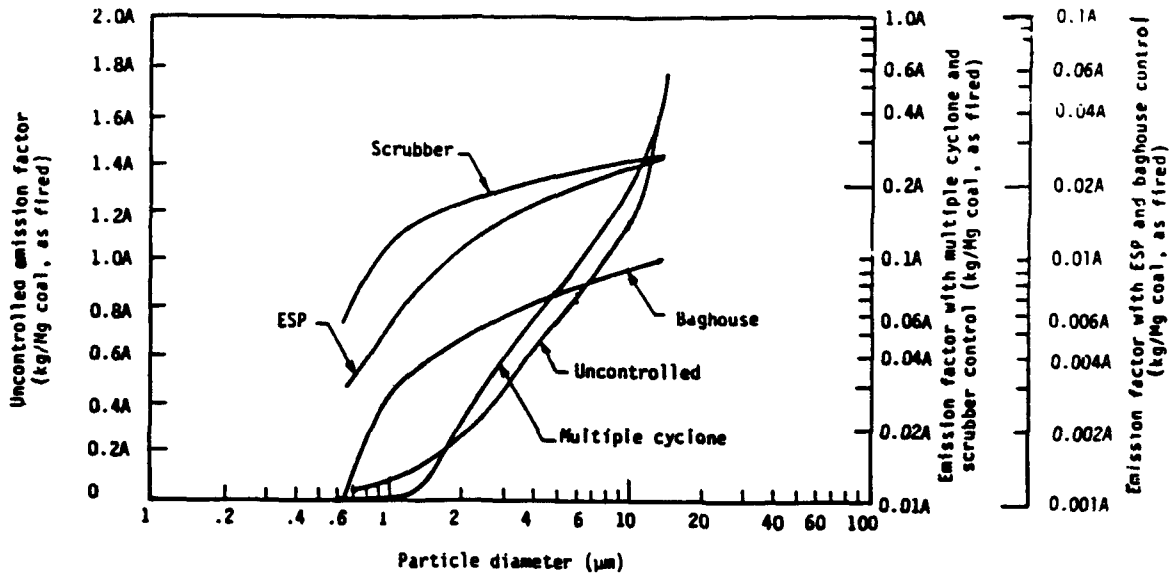


Figure 1.1-1. Cumulative size specific emission factors for dry bottom boilers burning pulverized bituminous coal.

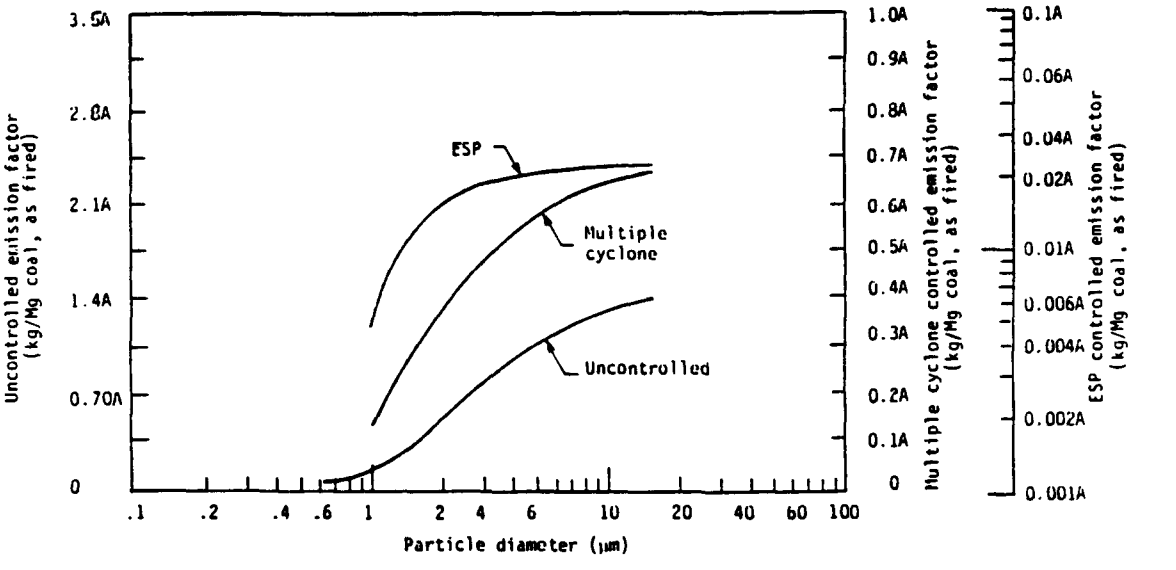


Figure 1.1-2. Cumulative specific emission factors for wet bottom boilers burning pulverized bituminous coal.

TABLE 1.1-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR WET BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS COAL[a]
(Emission Factor Rating: E)

Particle Size[b] (μm)	Cumulative Mass % ≤ stated size			Cumulative Emission Factor[c] [kg/Mg (lb/ton) coal, as fired]		
		Controlled			Controlled[d]	
	Uncontrolled	Multiple cyclones	ESP	Uncontrolled	Multiple cyclones	ESP
15	40	99	83	1.4A (2.8A)	0.69A (1.38A)	0.023A (0.46A)
10	37	93	75	1.30A (2.6A)	0.65A (1.3A)	0.021A (0.42A)
6	33	84	63	1.16A (2.32A)	0.59A (1.18A)	0.018A (0.36A)
2.5	21	61	40	0.74A (1.48A)	0.43A (0.86A)	0.011A (0.022A)
1.25	6	31	17	0.21A (0.42A)	0.22A (0.44A)	0.005A (0.01A)
1.00	4	19	8	0.14A (0.28A)	0.13A (0.26A)	0.002A (0.004A)
0.625	2	e	e	0.07A (0.14A)	e	e
TOTAL	100	100	100	3.5A (7.0A)	0.7A (1.4A)	0.028A (0.056A)

a. Reference 32. Applicable SCCs are 101002-12/21, 102002-01/21, and 103002-05/21.
b. Expressed as aerodynamic equivalent diameter.
c. A = coal ash weight %, as fired.
d. Estimated control efficiency for multiple cyclones is 94%; and for ESP, 99.2%.
e. Insufficient data.
ESP = Electrostatic precipitator.
SCC = Source classification code.

TABLE 1.1-7. CUMULATIVE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR CYCLONE FURNACES BURNING BITUMINOUS COAL[a]
(Emission Factor Rating: E)

Particle Size[b] (μm)	Cumulative Mass % ≤ stated size			Cumulative Emission Factor[c] [kg/Mg (lb/ton) coal, as fired]		
		Controlled			Controlled[e]	
	Uncontrolled	Multiple cyclones	ESP	Uncontrolled	Multiple cyclones	ESP
15	33	95	90	0.33A (0.66A)	0.057A (0.114A)	0.0064A (0.013A)
10	13	94	68	0.13A (0.26A)	0.056A (0.112A)	00054A (0.011A)
6	8	93	56	0.08A (0.16A)	0.056A (0.112A)	0.0045A (0.009A)
2.5	0	92	36	0	0.055A (0.11A)	0.0029A (0.006A)
1.25	0	85	22	0	0.051A (0.10A)	0.0018A (0.004A)
1.00	0	82	17	0	0.049A (0.10A)	0.0014A (0.003A)
0.625	0	d	d	0	d	d
TOTAL	100	100	100	1A (2A)	0.06A (0.12A)	0.008A (0.016A)

a. Reference 32. Applicable SCCs are 101002-03/23, 102002-03/23, and 103002-23/01.
b. Expressed as aerodynamic equivalent diameter.
c. A = coal ash weight %, as fired.
d. Insufficient data.
e. Estimated control efficiency for multiple cyclones is 94%; and for ESP, 99.2%.
ESP = Electrostatic precipitator.
SCC = Source classification code.

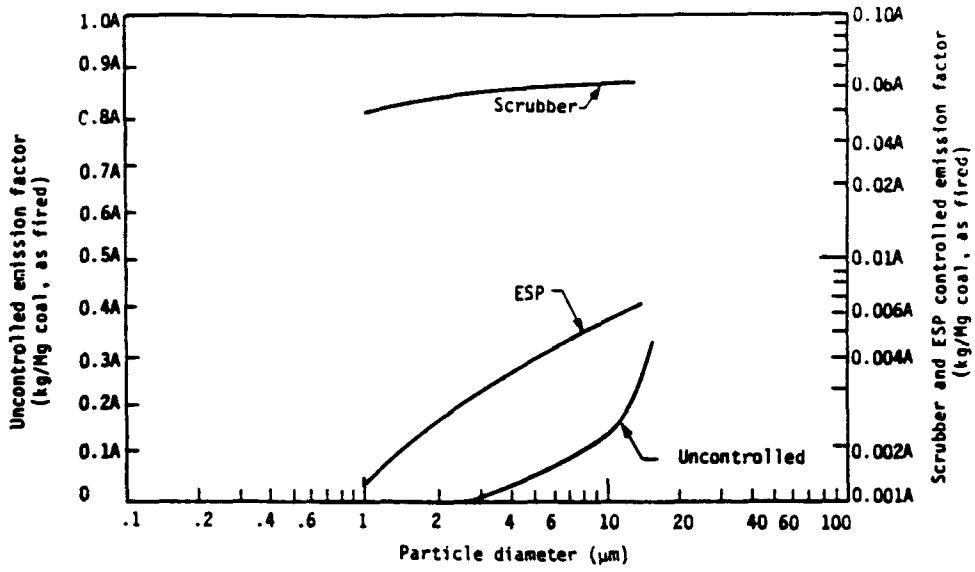


Figure 1.1-3. Cumulative size specific emission factors for cyclone furnaces burning bituminous coal.

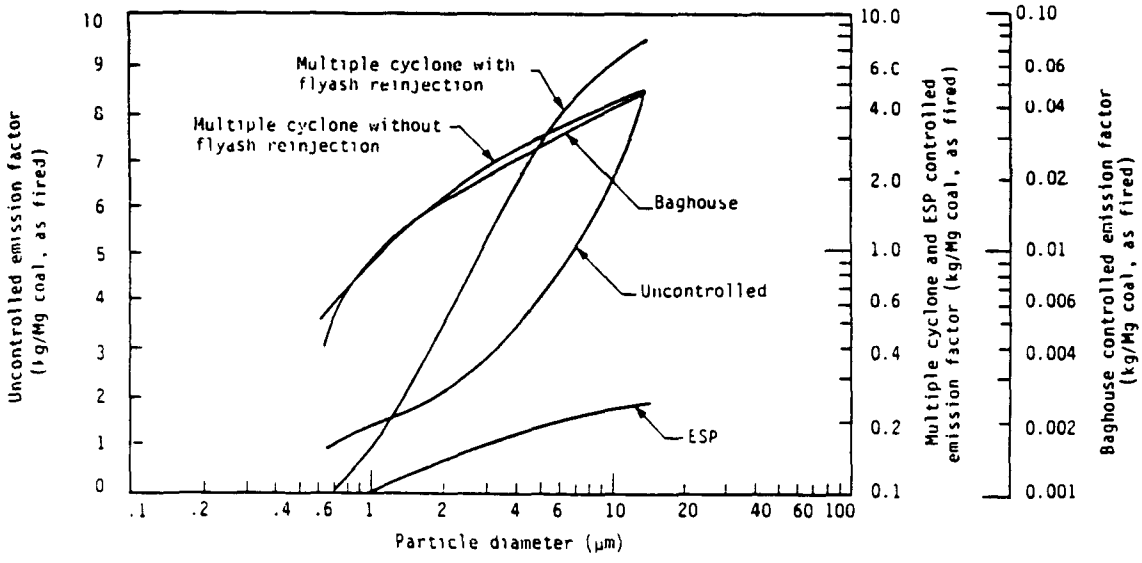


Figure 1.1-4. Cumulative size specific emission factors for spreader stokers burning bituminous coal.

TABLE 1.1-8. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR SPREADER STOKERS BURNING BITUMINOUS COAL[a]

Particle Size[b] (μm)	Cumulative Mass % ≤ stated size (SCC)					Cumulative Emission Factor[c] [kg/Mg (lb/ton) coal, as fired]									
		Controlled				Uncontrolled (101002-04/24 102002-04/24 103002-09/24)		Controlled[d]							
								Multiple cyclones[c] (101002-03/24 101002-04/24 103002-09/24)		Multiple cyclones[d] (101002-04/24 101002-04/24 103002-09/24)		ESP[f] (101002-04/24 102002-04/24 103002-09/24)		Baghouse[f] (101002-04/24 102002-04/24 103002-09/24)	
	Uncontrolled	Multiple cyclones[c]	Multiple cyclones[d]	ESP	Baghouse	Factor	Rating	Factor	Rating	Factor	Rating	Factor	Rating	Factor	Rating
15	28	56	74	97	72	8.4 (16.8)	C	4.4 (8.8)	E	0.23 (0.46)	C	0.043 (0.086)	E	0.010A (0.02A)	C
10	20	73	65	90	60	6.2 (12.4)	C	3.9 (7.8)	E	0.22 (0.44)	C	0.036 (0.072)	E	0.009A (0.02A)	C
6	14	51	52	82	46	4.3 (8.6)	C	3.1 (6 2)	E	0.20 (0.60)	C	0.028 (0.056)	E	0.008A (0.02A)	C
2.5	7	8	27	61	26	0 7 (1.4)	C	1.6 (3.2)	E	0.15 (0.30)	C	0.016 (0 032)	E	0.005A (0.01A)	C
1.25	5	2	16	46	18	0.2 (0 4)	C	1.0 (2.0)	E	0.11 (0.22)	C	0.011 (0.022)	E	0.003A (0.006A)	C
1.00	5	2	14	41	15	0.2 (0.4)	C	0.8 (1.6)	E	0.10 (0.20)	C	0 009 (0.018)	E	0 003A (0.006A)	C
0.625	4	1	9	e	7	0.1 (0.2)	C	0.5 (1.0)	E	e	C	0.004 (0.006)	E	0.001A (0.002A)	C
TOTAL	100	100	100	100	100	8.5 (17.0)	C	6.0 (12.0)	E	0.24[f] (0.48)	C	0.06[f] (0.12)	E	0.01A (0.02A)	C

a. Reference 32.
b. Expressed as aerodynamic equivalent diameter.
c. With flyash reinjection.
d. Without flyash reinjection.
e. Insufficient data.
f. Estimated control efficiency for ESP is 99.22%; and for baghouse, 99.8%.

ESP = Electrostatic precipitator.
SCC = Source classification code.

TABLE 1.1-9. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR OVERFEED STOKERS BURNING BITUMINOUS COAL[a]

Particle Size[b] (μm)	Cumulative Mass % ≤ stated size		Cumulative Emission Factor[c] [kg/Mg (lb/ton) coal, as fired]			
			Uncontrolled		Multiple Cyclones Controlled[d]	
	Uncontrolled	Multiple Cyclones Controlled	Factor	Rating	Factor	Rating
15	49	60	3.9 (7.8)	C	2.7 (5.4)	E
10	37	55	3.0 (6.0)	C	2.5 (5.0)	E
6	24	49	1.9 (3.8)	C	2.2 (4.4)	E
2.5	14	43	1.1 (2.2)	C	1.9 (3.8)	E
1.25	13	39	1.0 (2.0)	C	1.8 (3.6)	E
1.00	12	39	1.0 (2.0)	C	1.8 (3.6)	E
0.625	c	16	c	C	0.7 (1.4)	E
TOTAL	100	100	8.0 (16.0)	C	4.5 (9.0)	E

a. Reference 32. Applicable SCCs are 1001002-05/25, 102002-05/10/25, and 103002-07/25.
b. Expressed as aerodynamic equivalent diameter.
c. Insufficient data.
d. Estimated control efficiency for multiple cyclones is 80%.
SCC = Source classification code.

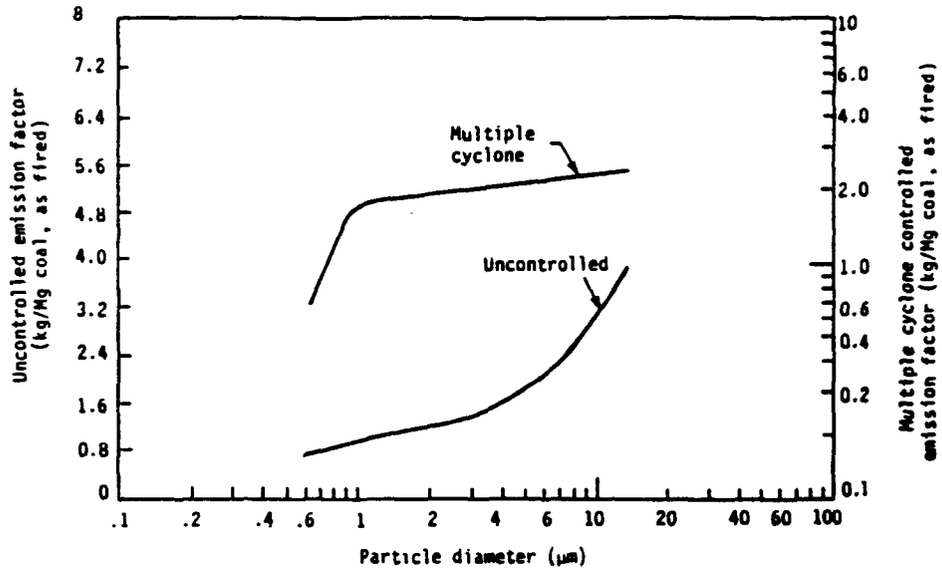


Figure 1.1-5. Cumulative size specific emission factors for overfeed stokers burning bituminous coal.

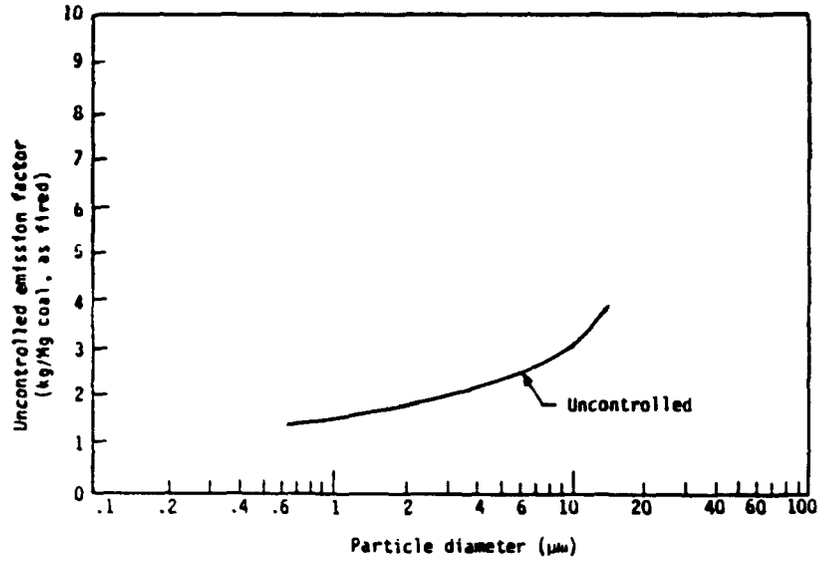


Figure 1.1-6. Cumulative specific emission factors for underfeed stokers burning bituminous coal.

TABLE 1.1-10. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR UNDERFEED STOKERS BURNING BITUMINOUS COAL[a]

Particle Size[b] (μm)	Cumulative Mass %, ≤ stated size	Uncontrolled Cumulative Emission Factor[c] [kg/Mg (lb/ton) coal, as fired]	
		Factor	Rating
15	50	3.8 (7.6)	C
10	41	3.1 (6.2)	C
6	32	2.4 (4.8)	C
2.5	25	1.9 (3.8)	C
1.25	22	1.7 (3.4)	C
1.00	21	1.6 (3.2)	C
0.625	18	1.4 (2.7)	C
TOTAL	100	7.5 (15.0)	C

a. Reference 32. Applicable SCCs are 102002-06 and 103002-08.
b. Expressed as aerodynamic equivalent diameter.
c. May also be used for uncontrolled hand-fired units.
SCC = Source classification code.

TABLE 1.1-11. (ENGLISH UNITS) EMISSION FACTORS FOR METHANE (CH_4), NON-METHANE TOTAL ORGANIC COMPOUNDS (NMTOC), AND NITROUS OXIDE (N_2O) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	SCC	CH_4[b]		NMTOC[b,c]		N_2O	
		Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating	Emission Factor lb/ton	Rating
Pulverized coal fired, dry bottom, wall fired	101002-02/22 102002-02/22 103002-06/22	0.04	B	0.06	B	.09	D
Pulverized coal fired, dry bottom, tangentially fired	101002-12/26 102002-12/26 103002-16/26	0.04	B	0.06	B	.03	D
Pulverized coal fired, wet bottom	101002-12/21 102002-01/21 103002-05/21	0.05	B	0.04	B	.09[e]	E
Cyclone furnace	101002-03/23 102002-03/23 103002-23	0.01	B	0.11	B	.09[e]	E
Spreader stoker	101002-04/24 102002-04/24 103002-09/24	0.06	B	0.05	B	.09[e]	E
Spreader stoker, with multiple cyclones, and reinjection	101002-03/24 101002-04/24 103002-09/24	0.06	B	0.05	B	.09[e]	E
Spreader stoker, with multiple cyclones, no reinjection	101002-04/24 101002-04/24 103002-09/24	0.06	B	0.05	B	.09[e]	E
Overfeed stoker[f]	101002-05/25 102002-05/10/25 103002-07/25	0.06	B	0.05	B	.09[e]	E
Overfeed stoker, with multiple cyclones[f]	101002-05/25 102002-05/10/25 103002-07/25	0.06	B	0.05	B	.09[e]	E
Underfeed stoker	102002-06 103002-08	0.8	B	1.3	B	.09[e]	E
Underfeed stoker, with multiple cyclone	102002-06 103002-08	0.8	B	1.3	B	.09[e]	E
Hand-fed units	103002-14	5	E	10	E	.09[e]	E
Fluidized bed combustor, bubbling bed	101002-17 102002-17 103002-17	0.06	E	0.05	E	5.9[g]	E
Fluidized bed combustor, circulating bed	101002-17 102002-17 103002-17	0.06	E	0.05	E	5.5	E

a. Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired.

b. Nominal values achievable under normal operating conditions. Values one or two orders of magnitude higher can occur when combustion is not complete.

c. Non-methane total organic compounds are expressed as C2 to C16 alkane equivalents

(Reference 31). Because of limited data, the effects of firing configuration on NMTOC emission factors could not be distinguished. As a result, all data were averaged collectively to develop a single average emission factor for pulverized coal units, cyclones, spreaders and overfeed stokers.

d. Refer to EPA/OAQPS's SPECIATE and XATEF data bases for emission factors on speciated VOC.

e. No data found; use emission factor for pulverized coal-fired dry bottom boilers.

f. Includes traveling grate, vibrating grate and chain grate stokers.

g. No data found; use emission factor for circulating fluidized bed.

SCC = Source classification code.

TABLE 1.1-12. (METRIC UNITS) EMISSION FACTORS FOR METHANE (CH_4), NON-METHANE TOTAL ORGANIC COMPOUNDS (NMTOC), AND NITROUS OXIDE (N_2O) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	SCC	CH_4[b]		NMTOC[b,c]		N_2O	
		Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating	Emission Factor kg/Mg	Rating
Pulverized coal fired, dry bottom, wall fired	101002-02/22 102002-02/22 103002-06/22	0.02	B	0.04	B	.045	D
Pulverized coal fired, dry bottom, tangentially fired	101002-12/26 102002-12/26 103002-16/26	0.02	B	0.04	B	.015	D
Pulverized coal fired, wet bottom	101002-12/21 102002-01/21 103002-05/21	0.025	B	0.02	B	.045[e]	E
Cyclone furnace	101002-03/23 102002-03/23 103002-23	0.005	B	0.055	B	.045[e]	E
Spreader stoker	101002-04/24 102002-04/24 103002-09/24	0.03	B	0.025	B	.045[e]	E
Spreader stoker, with multiple cyclones, and reinjection	101002-03/24 101002-04/24 103002-09/24	0.03	B	0.025	B	.045[e]	E
Spreader stoker, with multiple cyclones, no reinjection	101002-04/24 101002-04/24 103002-09/24	0.03	B	0.025	B	.045[e]	E
Overfeed stoker[f]	101002-05/25 102002-05/10/25 103002-07/25	0.03	B	0.025	B	.045[e]	E
Overfeed stoker, with multiple cyclones[f]	101002-05/25 102002-05/10/25 103002-07/25	0.03	B	0.025	B	.045[e]	E
Underfeed stoker	102002-06 103002-08	0.4	B	.65	B	.045[e]	E
Underfeed stoker, with multiple cyclone	102002-06 103002-08	0.4	B	.65	B	.045[e]	E
Hand-fed units	103002-14	2.5	E	5	E	.045[e]	E
Fluidized bed combustor, bubbling bed	101002-17 102002-17 103002-17	0.03	E	0.025	E	2.75[g]	E
Fluidized bed combustor, circulating bed	101002-17 102002-17 103002-17	0.03	E	0.025	E	2.75	E

a. Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired.
b. Nominal values achievable under normal operating conditions. Values one or two orders of magnitude higher can occur when combustion is not complete.
c. Non-methane total organic compounds are expressed as C2 to C16 alkane equivalents

(Reference 31). Because of limited data, the effects of firing configuration on NMTOC emission factors could not be distinguished. As a result, all data were averaged collectively to develop a single average emission factor for pulverized coal units, cyclones, spreaders and overfeed stokers.

d. Refer to EPA/OAQPS's SPECIATE and XATEF data bases for emission factors on speciated VOC.

e. No data found; use emission factor for pulverized coal-fired dry bottom boilers.

f. Includes traveling grate, vibrating grate and chain grate stokers.

g. No data found; use emission factor for circulating fluidized bed.

SCC = Source classification code.

TABLE 1.1-13. (ENGLISH UNITS) EMISSION FACTORS FOR TRACE ELEMENTS, POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]
(Emission Factor Rating: E)

Firing Configuration (SCC)	Emission Factor, lb/10^{12} Btu									
	As	Be	Cd	Cr	Pb	Mn	Hg	Ni	POM	HCOH
Pulverized coal, configuration unknown (no SCC)	NA	NA	NA	1922	NA	NA	NA	NA	NA	112[b]
Pulverized coal, wet bottom (10100201)	538	81	44-70	1020-	507	808-2980	16	840-1290	NA	NA
Pulverized coal, dry bottom (10100202)	684	81	44.4	1250-2570	507	228-2980	16	1030-1290	2.08	NA
Pulverized coal, dry bottom, tangential (10100212)	NA	NA	NA	NA	NA	NA	NA	NA	2.4	NA
Cyclone furnace (10100203)	115	<81	28	212-1502	507	228-1300	16	174-1290	NA	NA
Stoker, configuration unknown (no SCC)	NA	73	NA	19-300	NA	2170	16	775-1290	NA	NA
Spreader stoker (10100204)	264-542	NA	21-43	942-1570	507	NA	NA	NA	NA	221[c]
Traveling grate, overfeed stoker (10100205)	542-1030	NA	43-82	NA	507	NA	NA	NA	NA	140[d]

a. The emission factors in this table represent the ranges of factors reported in the literature. If only one data point was found, it is still reported in this table.
b. Based on 2 units; 456 MWe and 133 million Btu/hr.
c. Based on 1 unit; 59 million Btu/hr.
d. Based on 1 unit; 52 million Btu/hr.
SCC = Source classification code.
NA = Not available.

TABLE 1.1-14. (METRIC UNITS) EMISSION FACTORS FOR TRACE ELEMENTS, POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]
(Emission Factor Rating: E)

Firing Configuration (SCC)	Emission Factor, pg/J									
	As	Be	Cd	Cr	Pb	Mn	Hg	Ni	POM	HCOH
Pulverized coal, configuration unknown (no SCC)	NA	NA	NA	825	NA	NA	NA	NA	NA	48[b]
Pulverized coal, wet bottom (10100201)	231	35	18-30	439-676	218[c]	348-1282	7	361-555	NA	NA
Pulverized coal, dry bottom (10100202)	294	35	19	538-676	218[c]	98-1282	7	443-555	0.894	NA
Pulverized coal, dry bottom, tangential (10100212)	NA	NA	NA	NA	NA	NA	NA	NA	1.03	NA
Cyclone furnace (10100203)	49.5-133	<34.9	12	91.2-676	218[c]	98-5590	6.9	74.9-555	NA	NA
Stoker, configuration unknown (no SCC)	NA	31.4	NA	8.1-675	NA	934	6.9	334-555	NA	NA
Spreader stoker (10100204)	114-233	NA	9.0-18.5	404-674	218[c]	NA	NA	NA	NA	95[d]
Traveling grate, overfeed stoker (10100205)	233-443	NA	19-35	NA	218[c]	NA	NA	NA	NA	60[e]

a. The emission factors in this table represent the ranges of factors reported in the literature. If only one data point was found, it is still reported in this table.
b. Based on 2 units; 456 MWe and 39 MW.
c. Based on 1 unit; 17 MW.
d. Based on 1 unit; 15 MW.

SCC = Source classification code.
NA = Not available.

TABLE 1.1-15. NEW SOURCE PERFORMANCE STANDARDS FOR FOSSIL FUEL-FIRED BOILERS

Standard/ Boiler Types/ Applicability Criteria	Boiler Size MW (Million Btu/hr)	Fuel or Boiler Type	PM ng/J (lb/MMBtu) [% reduction]	SO_2 ng/J (lb/MMBtu) [% reduction]	NO_x ng/J (lb/MMBtu) [% reduction]
Subpart D	>73 (>250)	Gas	43 (0.10)	NA	86 (0.20)
Industrial-Utility		Oil	43 (0.10)	340 (0.80)	129 (0.30)
Commence construction after 8/17/71		Bit./Subbit. Coal	43 (0.10)	520 (1.20)	300 (0.70)
Subpart Da	>73 (>250)	Gas	13 (0.03 [NA]	340 (0.80) [90][a]	86 (020) [25]
Utility					
Commence construction after 9/18/78		Oil	13 (0.03) [70]	340 (0.80) [90][a]	130 (0.30) [30]
		Bit./Subbit. Coal	13 (0.03) [99]	520 (1.20) [90][b]	260/210[c] (0.60/0.50) [65/65]
Subpart Db	>29 (>100)	Gas	NA[d]	NA[d]	43[f] (0.10)
Industrial-Commercial-Institutional		Distillate Oil	43 (0.10)	340[f] (0.80) [90]	43[f] (0.10)
Commence construction after 6/19/84[k]		Residual Oil	(Same as for distillate oil)	(Same as for distillate oil)	130[g] (0.30)
		Pulverized Bit./Subbit. Coal	22[e] (0.05)	520[e] (1.20) [90]	300 (0.70)
		Spreader Stoker & FBC	22[e] (0.05)	520[e] (1.20) [90]	260 (0.60)
		Mass-Feed Stoker	22[e] (0.05)	520[e] (1.20) [90]	210 (0.50)
Subpart Dc	2.9 - 29 (10 - 100)	Gas	-[h]	-	-
Small Industrial-Commercial-Institutional		Oil	-[h,i]	215 (0.50)	-
Commence construction after 6/9/89		Bit. & Subbit. Coal	22[j] (0.05)	520[f] (1.20 [90]	-

a. Zero percent reduction when emissions are less than 86 ng/J (0.20 lb/MMBtu).
b. 70 percent reduction when emissions are less than 260 ng/J (0.60 lb/MMBtu).
c. The first number applies to bituminous coal and the second to subbituminous coal.

d. Standard applies when gas is fired in combination with coal, see 40 CFR 60, Subpart Db.
e. Standard is adjusted for fuel combinations and capacity factor limits, see 40 CFR 60, Subpart Db.
f. For furnace heat release rates greater than 730,000 J/s-m^3 (70,000 Btu/hr-ft^3), the standard is 86 ng/J (0.20 lb/MMBtu).
g. For furnace heat release rates greater than 730,000 J/s-m^3 (70,000 Btu/hr-ft^3), the standard is 170 ng/J (0.40 lb/MMBtu).
h. Standard applies when gas or oil is fired in combination with coal, see 40 CFR 60, Subpart Dc.
i. 20 percent capacity limit applies for heat input capacities of 8.7 Mwt (30 MMBtu/hr) or greater.
j. Standard is adjusted for fuel combinations and capacity factor limits, see 40 CFR 60, Subpart Dc.
k. Additional requirements apply to facilities which commenced construction, modification, or reconstruction after 6/19/84 but on or before 6/19/86 (see 40 Code of Federal Regulations Part 60, Subpart Db).
l. 215 ng/J (0.50 lb/million Btu) limit (but no percent reduction requirement) applies if facilities combust only very low sulfur oil (< 0.5 wt. % sulfur).

FBC = Fluidized bed combustion.

TABLE 1-16. POST-COMBUSTION SO_2 CONTROLS FOR COAL COMBUSTION SOURCES

Control Technology	Process	Typical Control Efficiencies	Remarks
Wet scrubber	Lime/limestone	80-95+%	Applicable to high sulfur fuels, Wet sludge product
	Sodium carbonate	80-98%	1-125 MW (5-430 million Btu/hr) typical application range, High reagent costs
	Magnesium oxide/hydroxide	80-95+%	Can be regenerated
	Dual alkali	90-96%	Uses lime to regenerate sodium-based scrubbing liquor
Spray drying	Calcium hydroxide slurry, vaporizes in spray vessel	70-90%	Applicable to low and medium sulfur fuels, Produces dry product
Furnace injection	Dry calcium carbonate/hydrate injection in upper furnace cavity	25-50%	Commercialized in Europe, Several U.S. demonstration projects underway
Duct injection	Dry sorbent injection into duct, sometimes combined with water spray	25-50+%	Several R&D and demonstration projects underway, Not yet commercially available in the U.S.

TABLE 1-17. COMBUSTION MODIFICATION NO_x CONTROLS FOR STOKER COAL-FIRED INDUSTRIAL BOILERS

Control Technique	Description of Technique	Effectiveness of Control (% NO_x reduction)	Range of Application	Commercial Availability/R&D Status	Comments
Low Excess Air (LEA)	Reduction of air flow under stoker bed	5-25	Excess oxygen limited to 5-6% minimum	Available now but need R&D on lower limit of excess air	Danger of overheating grate, clinker formation, corrosion, and high CO emissions
Staged combustion (LEA + OFA)	Reduction of undergrate air flow and increase of overfire air flow	5-25	Excess oxygen limited to 5% minimum	Most stokers have OFA ports as smoke control devices but may need better sir flow control devices	Need research to determined optimum location and orientation of OFA ports for NO_x emission control. Overheating grate, corrosion, and high CO emission can occur if undergrate airflow is reduced below acceptable level as in LEA
Load Reduction (LR)	Reduction of coal and air feed to the stoker	Varies from 49% decrease to 25% increase in NO_x (average 15% decrease)	Has been used down to 25% load	Available	Only stokers that can reduce load without increasing excess air. Not a desirable technique because of loss in boiler efficiency
Reduced air preheat (RAP)	Reduction of combustion air temperature	8	Combustion air temperature reduced from 473K to 453K	Available now if boiler has combustion air heater	Not a desirable technique because of loss in boiler efficiency
Ammonia injection	Injection of NH_3 in convective section of boiler	40-40 (from gas- and oil-fired boiler experience)	Limited by furnace geometry. Feasible NH_3 injection rate limited to 1.5 NH_3/NO	Commercially offered but not yet demonstrated	Elaborate NH_3 injection, monitoring, and control system required. Possible load restrictions on boiler and air preheater fouling by ammonium bisulfate

REFERENCES FOR SECTION 1.1

1. Steam, 38th Edition, Babcock and Wilcox, New York, 1975.

2. Control Techniques for Particulate Emissions from Stationary Sources, Volume I, EPA-450/3-81-005a, U.S. Environmental Protection Agency, Research Triangle Park, NC, April 1981.

3. Ibidem, Volume II, EPA-450/3-81-005b.

4. Electric Utility Steam Generating Units: Background Information for Proposed Particulate Matter Emission Standard, EPA-450/2-78-006a, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1978

5. Axtman, W. and H.A. Eleniewski, "Field Test Results of Eighteen Industrial Coal Stoker Fired Boilers for Emission Control and Improved Efficiency", Presented at the 74th Annual Meeting of the Air Pollution Control Association, Philadelphia, PA, June 1981.

6. Field Tests of Industrial Stoker Coal Fired Boilers for Emission Control and Efficiency Improvement - Sites L1-17, EPA-600/7-81-020a, U.S. Environmental Protection Agency, Washington D.C., February 1981.

7. Control Techniques for Sulfur Dioxide Emissions from Stationary Sources, 2nd Edition, EPA-450/3-81-004, U.S. Environmental Protection Agency, Research Triangle Park, NC, April 1981.

8. Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards, EPA-450/2-78-007a, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1978.

9. Castaldini, Carlo and Meredith Angwin, Boiler Design and Operating Variables Affecting Uncontrolled Sulfur Emissions from Pulverized Coal Fired Steam Generators, EPA-450/3-77-047, U.S. Environmental Protection Agency, Research Triangle Park, NC, December 1977.

10. Control Techniques for Nitrogen Oxides Emissions from Stationary Sources, 2nd Edition, EPA-450/1-78-001, U.S. environmental Protection Agency, Research Triangle Park, NC, January 1978.

11. Review of NO_x Emission Factors for Stationary Fossil Fuel Combustion Sources, EPA-450/4-79-021, U.S. Environmental Protection Agency, Research Triangle Park, NC, September 1979.

12. Gaglia, B.N. and A. Hall, "Comparison of Bubbling and Circulating Fluidized Bed Industrial Steam Generation", Proceedings of 1987 International Fluidized Bed Industrial Steam Conference, American Society of Mechanical Engineers, New York, 1987.

13. Cushing, K., Belba, V., and Chang, R., "Fabric Filtration Experience Downstream from Atmospheric Fluidized Bed Combustion Boilers", presented at the Ninth Particulate Control Symposium, October 1991.

14. Overview of thee Regulatory Baseline, Technical Basis, and Alternative Control Levels for Sulfur Dioxide (SO_2) Emission Standards for Small Steam Generating Units, EPA-450/3-89-12, U.S. Environmental Protection Agency, Research Triangle Park, NC, May 1989.

15. Fossil Fuel Fired Industrial Boilers - Background Information - Volume I, EPA-450/3-82-006a, U.S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.

16. EPA Industrial Boiler FGD Survey: First Quarter 1979, EPA-600/7-79-067b, U.S. Environmental Protection Agency, Research Triangle Park, NC, April 1979.

17. Particulate Polycyclic Organic Matter, National Academy of Sciences, Washington, DC, 1972

18. Vapor Phase Organic Pollutants - Volatile Hydrocarbons and Oxidation Products, National Academy of Sciences, Washington, DC, 1976.

19. Lim, K.J., et.al., Industrial Boiler Combustion Modification NO_x Controls - Volume I Environmental Assessment, EPA-600/7-81-126a, U.S. Environmental Protection Agency, Washington, D.C., July 1981.

20. Hagebruack, R.P., D.J. Von Lehmden, and J.E. Meeker, "Emissions and Polynuclear Hydrocarbons and Other Pollutants from Heat-Generation and Incineration Process", Journal of the Air Pollution Control Assoction, 14:267-278, 1964.

21. Rogozen, M.B., et al., Formaldehyde: A Survey of Airborne Concentration and Sources, California Air Resources Board, ARB report no. ARB/R-84-231, 1984.

22. Lim, K.J., et al., Technology Assessment Report for Industrial Boiler Applications: NO_x Combustion Modification, EPA-600/7-79-178f, U.S. Environmental Protection Agency, Research Triangle Park, NC, December 1979.

23. Clean Air Act Amendments of 1990, Conference Report to Accompany S. 1603, Report 101-952, U.S. Government Printing Office, Washington, DC, October 26, 1990.

24. Klein, D.H., et al., "Pathways of Thirty-Seven Trace Elements Through Coal-Fired Power Plants", Environmental Science and Technology., 9: 973-979, 1975.

25. Coles, D.G., et al., "Chemical Studies of Stack Fly Ash from a Coal-Fired Power Plant", Environmental Science and Technology, 13: 455-459, 1979.

26. Baig, S., et al., Conventional Combustion Environmental Assessment, EPA Contract No. 68-02-3138, U.S. Environmental Protection Agency, Research Triangle Park, NC, 1981.

27. Technology Assessment Report for Industrial Boiler Applications: NO_x Combustion Modification, EPA-600/7-79-178f, U.S. Environmental Protection Agency, Washington, DC, December 1979.

28. Standards of Performance for New Stationary Sources, 36 FR 24876, December 23, 1971.

29. Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers - Phase I, EPA-650/2-74-078a, U.S. Environmental Protection Agency, Washington, DC, October 1974.

30. Source Sampling Residential Fireplaces for Emission Factor Development, EPA-450/3-76-010, U.S. Environmental Protection Agency, Research Triangle Park, NC, November 1875.

31. Emissions of Reactive Volatile Organic Compounds from Utility Boilers, EPA-600/7-80-111, U.S. Environmental Protection Agency, Washington DC, May 1980.

32. Inhalable Particulate Source Category Report for External Combustion Sources, EPA Contract No. 68-02-3156, Acurex Corporation, Mountain View, CA, January 1985.

33. Brown, S.W., et al., "Gas Reburn System Operating Experience on a Cyclone Boiler," presented at the NO_x Controls For Utility Boilers Conference, Cambridge, MA, July 1992.

34. Emission Factor Documentation For AP-42 Section 1.1 - Bituminous and Subbituminous Coal Combustion - Draft, U.S. Environmental Protection Agency, Research Triangle Park, NC, March 1993.

1.2 ANTHRACITE COAL COMBUSTION

1.2.1 General[1-4]

Anthracite coal is a high-rank coal with more fixed carbon and less volatile matter than either bituminous coal or lignite; anthracite also has higher ignition and ash fusion temperatures. In the United States, nearly all anthracite is mined in northeastern Pennsylvania and consumed in Pennsylvania and its surrounding states. The largest use of anthracite is for space heating. Lesser amounts are employed for steam/electric production; coke manufacturing, sintering and pelletizing; and other industrial uses. Anthracite currently is only a small fraction of the total quantity of coal combusted in the United States.

Another form of anthracite coal burned in boilers is anthracite refuse, commonly known as culm. Culm was produced as breaker reject material from the mining/sizing of anthracite coal and was typically dumped by miners on the ground near operating mines. It is estimated that there are over 15 million Mg (16 million tons) of culm scattered in piles throughout northeastern Pennsylvania. The heating value of culm is typically in the 1,400 to 2,800 kcal/kg (2,500 to 5,000 Btu/lb) range, compared to 6,700 to 7,800 kcal/kg (12,000 to 14,000 Btu/lb) for anthracite coal.

1.2.2 Firing Practices[5-7]

Due to its low volatile matter content, and non-clinkering characteristics, anthracite coal is largely used in medium-sized industrial and institutional stoker boilers equipped with stationary or traveling grates. Anthracite coal is not used in spreader stokers because of its low volatile matter content and relatively high ignition temperature. This fuel may also be burned in pulverized coal-fired (PC-fired) units, but due to ignition difficulties, this practice is limited to only a few plants in eastern Pennsylvania. Anthracite coal has also been widely used in hand-fired furnaces. Culm has been combusted primarily in fluidized bed combustion (FBC) boilers because of its high ash content and low heating value.

Combustion of anthracite coal on a traveling grate is characterized by a coal bed of 8 to 13 cm (3 to 5 inches) in depth and a high blast of underfire air at the rear or dumping end of the grate. This high blast of air lifts incandescent fuel particles and combustion gases from the grate and reflects the particles against a long rear arch over the grate towards the front of the fuel bed where fresh or "green" fuel enters. This special furnace arch design is required to assist in the ignition of the green fuel.

A second type of stoker boiler used to burn anthracite coal is the underfeed stoker. Various types of underfeed stokers are used in industrial boiler applications but the most common for anthracite coal firing is the single-retort side-dump stoker with stationary grates. In this unit, coal is fed intermittently to the fuel bed by a ram. In very small units the coal is fed continuously by a screw. Feed coal is pushed through the retort and upward towards the tuyere blocks. Air is supplied through the tuyere blocks on each side of the retort and through openings in the side grates. Overfire air is commonly used with underfeed stokers to provide combustion air and turbulence in the flame zone directly above the active fuel bed.

In PC-fired boilers, the fuel is pulverized to the consistency of powder and pneumatically injected through burners into the furnace. Injected coal particles burn in suspension within the furnace region of the boiler. Hot flue gases rise from the furnace and provide heat exchange with boiler tubes in the walls and upper regions of the boiler. In general, PC-fired boilers operate either in a wet-bottom or dry bottom mode; because of its high ash fusion temperature, anthracite coal is burned in dry-bottom furnaces.

For anthracite culm, combustion in conventional boiler systems is difficult due to the fuel's high ash content, high moisture content, and low heating value. However, the burning of culm in a fluidized bed system was demonstrated at a steam generation plant in Pennsylvania. A fluidized bed consists of inert particles (e.g., rock and ash) through which air is blown so that the bed behaves as a fluid. Anthracite coal enters in the space above the bed and burns in the bed. Fluidized beds can handle fuels with moisture contents up to near 70 percent (total basis) because of the large thermal mass represented by the hot inert bed particles. Fluidized beds can also handle fuels with ash contents as high as 75 percent. Heat released by combustion is transferred to in-bed steam-generating tubes. Limestone may be added to the bed to capture sulfur dioxide formed by combustion of fuel sulfur.

1.2.3 Emissions And Controls[4-6]

Particulate matter (PM) emissions from anthracite coal combustion are a function of furnace firing configuration, firing practices (boiler load, quantity and location of underfire air, soot blowing, flyash reinjection, etc.), and the ash content of the coal. Pulverized coal-fired boilers emit the highest quantity of PM per unit of fuel because they fire the anthracite in suspension, which results in a high percentage of ash carryover into exhaust gases. Traveling grate stokers and hand fired units produce less PM per unit of fuel fired, and coarser particulates, because combustion takes place in a quiescent fuel bed without significant ash carryover into the exhaust gases. In general, PM emissions from traveling grate stokers will increase during soot blowing and flyash reinjection and with higher fuel bed underfeed air flowrates. Smoke production during combustion is rarely a problem, because of anthracite's low volatile matter content.

Limited data are available on the emission of gaseous pollutants from anthracite combustion. It is assumed, based on bituminous coal combustion data, that a large fraction of the fuel sulfur is emitted as sulfur oxides. Also, because combustion equipment, excess air rates, combustion temperatures, etc., are similar between anthracite and bituminous coal combustion, nitrogen oxide emissions are also assumed to be similar. Nitrogen oxide emissions from FBC units burning culm are typically lower than from other anthracite coal-burning boilers due to the lower operating temperatures which characterize FBC beds.

Carbon monoxide and total organic compound emissions are dependent on combustion efficiency. Generally their emission rates, defined as mass of emissions per unit of heat input, decrease with increasing boiler size. Organic compound emissions are expected to be lower for pulverized coal units and higher for underfeed and overfeed stokers due to relative combustion efficiency levels.

Controls on anthracite emissions mainly have been applied to PM. The most efficient particulate controls, fabric filters, scrubbers, and electrostatic precipitators, have been installed on large pulverized anthracite-fired boilers. Fabric filters can achieve collection efficiencies exceeding 99 percent. Electrostatic precipitators typically are only 90 to 97 percent efficient, because of the

characteristic high resistivity of low sulfur anthracite fly ash. It is reported that higher efficiencies can be achieved using larger precipitators and flue gas conditioning. Mechanical collectors are frequently employed upstream from these devices for large particle removal.

Older traveling grate stokers are often uncontrolled. Indeed, particulate control has often been considered unnecessary, because of anthracite's low smoking tendencies and the fact that a significant fraction of large size flyash from stokers is readily collected in flyash hoppers as well as in the breeching and base of the stack. Cyclone collectors have been employed on traveling grate stokers, and limited information suggests these devices may be up to 75 percent efficient on particulate. Flyash reinjection, frequently used in traveling grate stokers to enhance fuel use efficiency, tends to increase PM emissions per unit of fuel combusted. High-energy venturi scrubbers can generally achieve PM collection efficiencies of 90 percent or greater.

Emission factors and ratings for pollutants from anthracite coal combustion and anthracite culm combustion are given in Tables 1.2-1 through 1.2-7. Cumulative size distribution data and size specific emission factors and ratings for particulate emissions are summarized in Table 1.2-8. Uncontrolled and controlled size specific emission factors are presented in Figure 1.2-1. Particle size distribution data for bituminous coal combustion may be used for uncontrolled emissions from pulverized anthracite-fired furnaces, and data for anthracite-fired traveling grate stokers may be used for hand fired units.

Table 1.2-1. EMISSION FACTORS FOR SPECIATED METALS FROM ANTHRACITE COAL COMBUSTION IN STOKER FIRED BOILERS[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor Range		Average Emission Factor	
	kg/Mg	lb/ton	kg/Mg	lb/ton
Mercury	4.4E-05 - 6.5E-05	8.7E-05 - 1.3E-04	6.5E-05	1.3E-04
Arsenic	BDL[b] - 1.2E-04	BDL - 2.4E-04	9.3E-05	1.9E-04
Antimony	BDL	BDL	BDL	BDL
Beryllium	1.5E-05 - 2.7E-04	3.0E-05 - 5.4E-04	1.5E-04	3.1E-04
Cadmium	2.3E-05 - 5.5E-03	4.5E-05 - 1.1E-04	3.6E-05	7.1E-05
Chromium	3.0E-03 - 2.5E-02	5.9E-03 - 4.9E-02	1.4E-02	2.8E-02
Manganese	4.9E-04 - 2.7E-03	9.8E-04 - 5.3E-03	1.8E-03	3.6E-03
Nickel	3.9E-03 - 1.8E-02	7.8E-03 - 3.5E-02	1.3E-02	2.6E-02
Selenium	2.4E-04 - 1.1E-03	4.7E-04 - 2.1E-03	6.3E-04	1.3E-03

[a]Reference 9. Units are kg of pollutant/Mg of coal burned and lbs. of pollutant/ton of coal burned. Source Classification Codes are 10100102, 10200104, and 10300102.
[b]BDL = Below detection limit.

Table 1.2-2. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC) AND METHANE (CH_4) FROM ANTHRACITE COAL COMBUSTORS[a]

Source Category (SCC)[b]	TOC Emission Factor			CH_4 Emission Factor		
	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating
Stoker fired boilers[c] (SCC 10100102, 10200104, 10300102)	0.10	0.20	E	ND	ND	-
Residential space[d] heaters (no SCC)	ND[e]	ND	-	4	8	E

[a]Units are kg of pollutant/Mg of coal burned and lbs. of pollutant/ton of coal burned.
[b]SCC = Source Classification Code.
[c]Reference 9.
[d]Reference 14.
[e]ND = No data.

Table 1.2-3 (Metric Units). EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM ANTHRACITE COAL COMBUSTORS[a]

EMISSION FACTOR RATING: E

Pollutant	Stoker Fired Boilers[b] (SCC 10100102, 10200104, 10300102)	Residential Space Heaters[c] (No SCC)	
	Emission Factor	Emission Factor Range	Emission Factor
Biphenyl	1.25E-02	ND	ND
Phenanthrene	3.4E-03	4.6E-02 - 2.1E-02	1.6E-01
Naphthalene	0.65E-01	4.5E-03 - 2.4E-02	1.5E-01
Acenaphthene	ND[d]	7.0E-03 - 3.4E-01	3.5E-01
Acenaphthalene	ND	7.0E-03 - 2.0E-02	2.5E-01
Fluorene	ND	4.5E-03 - 2.9E-02	1.7E-02
Anthracene	ND	4.5E-03 - 2.3E-02	1.6E-02
Fluoranthrene	ND	4.8E-02 - 1.7E-01	1.1E-01
Pyrene	ND	2.7E-02 - 1.2E-01	7.9E-02
Benzo(a)anthracene	ND	7.0E-03 - 1.0E-01	2.8E-01
Chrysene	ND	1.2E-02 - 1.1E-01	5.3E-02
Benzo(k)fluoranthrene	ND	7.0E-03 - 3.1E-02	2.5E-01
Benzo(e)pyrene	ND	2.3E-03 - 7.3E-03	4.2E-03
Benzo(a)pyrene	ND	1.9E-03 - 4.5E-03	3.5E-03
Perylene	ND	3.8E-04 - 1.2E-03	8.5E-04
Indeno(123-cd) perylene	ND	2.3E-03 - 7.0E-03	2.4E-01
Benzo(g,h,i,) perylene	ND	2.2E-03 - 6.0E-03	2.1E-01
Anthanthrene	ND	9.5E-05 - 5.5E-04	3.5E-03
Coronene	ND	5.5E-04 - 4.0E-03	1.2E-02

[a]Units are kg of pollutant/Mg of anthracite coal burned. SCC = Source Classification Code.
[b]Reference 9.
[c]Reference 14.
[d]ND = No data.

Table 1.2-4 (English Units). EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM ANTHRACITE COAL COMBUSTORS[a]

EMISSION FACTOR RATING: E

Pollutant	Stoker Fired Boilers[b] (SCC 10100102, 10200104, 10300102)	Residential Space Heaters[c] (No SCC)	
	Emission Factor	Emission Factor Range	Emission Factor
Biphenyl	2.5E-02	ND	ND
Phenanthrene	6.8E-03	9.1E-02 - 4.3E-02	3.2E-01
Naphthalene	1.3E-01	9.0E-03 - 4.8E-02	3.0E-01
Acenaphthene	ND[d]	1.4E-02 - 6.7E-01	7.0E-01
Acenaphthalene	ND	1.4E-02 - 3.0E-01	4.9E-01
Fluorene	ND	9.0E-03 - 5.8E-02	3.4E-02
Anthracene	ND	9.0E-03 - 4.5E-02	3.3E-02
Fluoranthrene	ND	9.6E-02 - 3.3E-01	2.2E-01
Pyrene	ND	5.4E-02 - 2.4E-01	1.6E-01
Benzo(a)anthracene	ND	1.4E-02 - 2.0E-01	5.5E-01
Chrysene	ND	2.3E-02 - 2.2E-01	1.1E-01
Benzo(k)fluoranthrene	ND	1.4E-02 - 6.3E-02	5.0E-01
Benzo(e)pyrene	ND	4.5E-03 - 1.5E-02	8.4E-03
Benzo(a)pyrene	ND	3.8E-03 - 9.0E-03	7.0E-03
Perylene	ND	7.6E-04 - 2.3E-03	1.7E-03
Indeno(123-cd) perylene	ND	4.5E-03 - 1.4E-02	4.7E-01
Benzo(g,h,i,) perylene	ND	4.3E-03 - 1.2E-02	4.2E-01
Anthanthrene	ND	1.9E-04 - 1.1E-03	7.0E-03
Coronene	ND	1.1E-03 - 8.0E-03	2.4E-02

[a]Units are lbs. of pollutant/ton of anthracite coal burned. SCC = Source Classification Code.
[b]Reference 9.
[c]Reference 14.
[d]ND = No data.

Table 1.2-5. EMISSION FACTORS FOR PARTICULATE MATTER (PM), AND LEAD (Pb) FROM ANTHRACITE COAL COMBUSTORS[a]

Source Category (SCC)[b]	Filterable PM Emission Factor			Condensible PM Emission Factor			Pb Emission Factor		
	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating
Stoker fired boilers[c] (SCC 10100102, 10200104, 10300102)	0.4A[d]	0.8A	C	0.04A	0.08A	C	4.5E-03	8.9E-03	E
Hand fired units[e] (SCC 10200207, 10300103)	5	10	B	ND[f]	ND		ND	ND	

[a]Units are kg of pollutant/Mg of coal burned and lbs. of pollutant/ton of coal burned.
[b]SCC = Source Classification Code.
[c]References 9-12.
[d]A = ash content of fuel, weight percent.
[e]Reference 16.
[f]ND = No data.

Table 1.2-6. EMISSION FACTORS FOR NITROGEN OXIDE COMPOUNDS (NO_x) AND SULFUR DIOXIDE (SO_2) FROM ANTHRACITE COAL COMBUSTORS[a]

Source Category (SCC)[b]	NO_x Emission Factor[c]			SO_2 Emission Factor[d]		
	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating
Stoker fired boilers[e] (SCC 10100102, 10200104, 10300102)	4.6	9.0	C	19.5S[f]	39S	B
FBC boilers[g] (no SCC)	0.9	1.8	E	1.5	2.9	E
Pulverized coal boilers (SCC 10100101, 10200101, 10300101)	9	18	B	19.5S	39S	B
Residential space heaters (no SCC)	1.5	3	B	19.5S	39S	B

[a]Units are kg of pollutant/Mg of coal burned and lbs. of pollutant/ton of coal burned.
[b]SCC = Source Classification Code.
[c]References 17-18.
[d]Reference 19.
[e]References 10-11.
[f]S = weight percent sulfur.
[g]Reference 15. FBC = Fluidized bed combustion; FBC boilers burning culm fuel; all other sources burning anthracite coal.

Table 1.2-7. EMISSION FACTORS FOR CARBON MONOXIDE (CO) AND CARBON DIOXIDE (CO_2) FROM ANTHRACITE COAL COMBUSTORS[a]

Source Category (SCC)[b]	CO Emission Factor			CO_2 Emission Factor		
	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating
Stoker fired boilers[c] (SCC 10100102, 10200104, 10300102)	0.3	0.6	B	2840	5680	C
FBC boilers[d] (no SCC)	0.15	0.3	E	ND[e]	ND	

[a]Units are kg of pollutant/Mg of coal burned and lbs. of pollutant/ton of coal burned.
[b]SCC = Source Classification Code.
[c]References 10, 13.
[d]Reference 15. FBC = Fluidized bed combustion; FBC boilers burning culm fuel; all other sources burning anthracite coal.
[e]ND = No data.

Table 1.2-8. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR DRY BOTTOM BOILERS BURNING PULVERIZED ANTHRACITE COAL[a]

EMISSION FACTOR RATING: D

Particle Size[b] (μm)	Cumulative Mass % ≤ stated size			Cumulative Emission Factor[d] kg/Mg (lb/ton) coal, as fired		
	Uncontrolled	Controlled[c]		Uncontrolled	Controlled[c]	
		Multiple Cyclone	Baghouse		Multiple Cyclone	Baghouse
15	32	63	79	1.6A (3.2A)[e]	0.63A (1.26A)	0.0079A (0.016A)
10	23	55	67	1.2A (2.3A)	0.55A (1.10A)	0.0067A (0.013A)
6	17	46	51	0.9A (1.7A)	0.46A (0.92A)	0.0051A (0.010A)
2.5	6	24	32	0.3A (0.6A)	0.24A (0.48A)	0.0032A (0.006A)
1.25	2	13	21	0.1A (0.2A)	0.13A (0.26A)	0.0021A (0.004A)
1.00	2	10	18	0.1A (0.2A)	0.10A (0.20A)	0.0018A (0.004A)
0.625	1	7		0.05A (0.1A)	0.07A (0.14A)	f
TOTAL	100	100	100	5A (10A)	1A (2A)	0.01A (0.02A)

[a]Reference 8. Source Classification Codes are 10100101, 10200101, and 10300101.
[b]Expressed as aerodynamic equivalent diameter.
[c]Estimated control efficiency for multiple cyclone is 80%; for baghouse, 99.8%.
[d]Units are kg of pollutant/Mg of coal burned and lbs. of pollutant/ton of coal burned.
[e]A = coal ash weight %, as fired.
[f]Insufficient data.

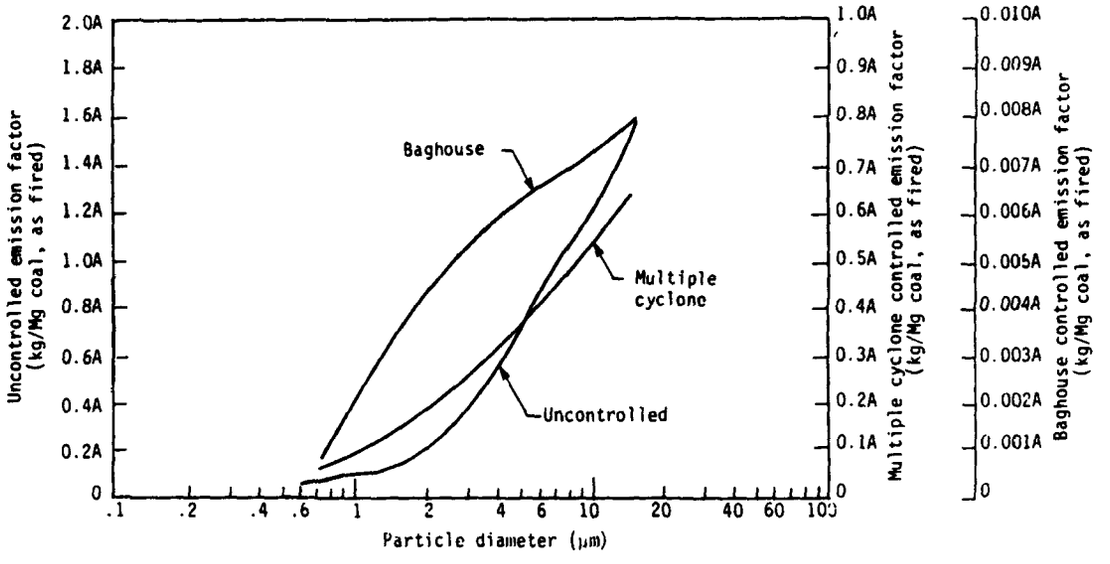


Figure 1.2-1. Cumulative size specific emission factors for dry bottom boilers burning pulverized anthracite coal.

References For Section 1.2

1. *Minerals Yearbook*, 1978-79, Bureau of Mines, U. S. Department of the Interior, Washington, DC, 1981.

2. *Air Pollutant Emission Factors*, APTD-0923, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1970.

3. P. Bender, D. Samela, W. Smith, G. Tsoumpas, and J. Laukaitis, "Operating Experience at the Shamokin Culm Burning Steam Generation Plant", Presented at the 76th Annual Meeting of the Air Pollution Control Association, Atlanta, GA, June 1983.

4. *Chemical Engineers' Handbook, Fourth Edition*, J. Perry, Editor, McGraw-Hill Book Company, New York, NY, 1963.

5. *Background Information Document For Industrial Boilers*, EPA 450/3-82-006a, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.

6. *Steam: Its Generation and Use, Thirty-Seventh Edition*, The Babcock & Wilcox Company, New York, NY, 1963.

7. *Emission Factor Documentation for AP-42 Section 1.2 - Anthracite Coal Combustion (Draft)*, Technical Support Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1993.

8. *Inhalable Particulate Source Category Report for External Combustion Sources*, EPA Contract No. 68-02-3156, Acurex Corporation, Mountain View, CA, January 1985.

9. *Emissions Assessment of Conventional Stationary Combustion Systems*, EPA Contract No. 68-02-2197, GCA Corp., Bedford, MA, October 1980.

10. *Source Sampling of Anthracite Coal Fired Boilers, RCA-Electronic Components, Lancaster, PA, Final Report*, Scott Environmental Technology, Inc., Plumsteadville, PA, April 1975.

11. *Source Sampling of Anthracite Coal Fired Boilers, Shippensburg State College, Shippensburg, PA, Final Report*, Scott Environmental Technology, Inc, Plumsteadville, PA, May 1975.

12. *Source Sampling of Anthracite Coal Fired Boilers, Pennhurst Center, Spring City, PA, Final Report*, TRC Environmental Consultants, Inc., Wethersfield, CT, January 23, 1980.

13. *Source Sampling of Anthracite Coal Fired Boilers, West Chester State College, West Chester, PA*, Pennsylvania Department of Environmental Resources, Harrisburg, PA 1980.

14. *Characterization of Emissions of PAHs From Residential Coal Fired Space Heaters*, Vermont Agency of Environmental Conservation, 1983.

References For Section 1.2 (Continued)

15. *Design, Construction, Operation, and Evaluation of a Prototype Culm Combustion Boiler/Heater Unit*, Contract No. AC21-78ET12307, U. S. Dept. of Energy, Morgantown Energy Technology Center, Morgantown, WV, October 1983.

16. *Air Pollutant Emission Factors*, APTD-0923, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1970.

17. *Source Test Data on Anthracite Fired Traveling Grate Stokers*, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1975.

18. N. F. Suprenant, *et al.*, *Emissions Assessment of Conventional Stationary Combustion Systems, Volume IV: Commercial/Institutional Combustion Sources*, EPA Contract No. 68-02-2197, GCA Corporation, Bedford, MA, October 1980.

19. R. W. Cass and R. W. Bradway, *Fractional Efficiency of a Utility Boiler Baghouse: Sunbury Steam Electric Station*, EPA-600/2-76-077a, U. S. Environmental Protection Agency, Washington, DC, March 1976.

1.3 FUEL OIL COMBUSTION

1.3.1 General[1-2, 26]

Two major categories of fuel oil are burned by combustion sources: distillate oils and residual oils. These oils are further distinguished by grade numbers, with Nos. 1 and 2 being distillate oils; Nos. 5 and 6 being residual oils; and No. 4 either distillate oil or a mixture of distillate and residual oils. No. 6 fuel oil is sometimes referred to as Bunker C. Distillate oils are more volatile and less viscous than residual oils. They have negligible nitrogen and ash contents and usually contain less than 0.3 percent sulfur (by weight). Distillate oils are used mainly in domestic and small commercial applications. Being more viscous and less volatile than distillate oils, the heavier residual oils (Nos. 5 and 6) must be heated for ease of handling and to facilitate proper atomization. Because residual oils are produced from the residue remaining after the lighter fractions (gasoline, kerosene, and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Residual oils are used mainly in utility, industrial, and large commercial applications.

1.3.2 Emissions[27]

Emissions from fuel oil combustion depend on the grade and composition of the fuel, the type and size of the boiler, the firing and loading practices used, and the level of equipment maintenance. Because the combustion characteristics of distillate and residual oils are different, their combustion can produce significantly different emissions. In general, the baseline emissions of criteria and non-criteria pollutants are those from uncontrolled combustion sources. Uncontrolled sources are those without add-on air pollution control (APC) equipment or other combustion modifications designed for emission control. Baseline emissions for sulfur dioxide (SO_2) and particulate matter (PM) can also be obtained from measurements taken upstream of APC equipment.

In this section, point source emissions of nitrogen oxides (NO_x), SO_2, PM, and carbon monoxide (CO) are being evaluated as criteria pollutants (those emissions which have established National Primary and Secondary Ambient Air Quality Standards. Particulate matter emissions are sometimes reported as total suspended particulate (TSP). More recent data generally quantify the portion of inhalable PM which is considered to be less than 10 microns in aerodynamic diameter (PM-10). In addition to the criteria pollutants, this section includes point source emissions of some non-criteria pollutants, nitrous oxide (N_2O), volatile organic compounds (VOCs), and hazardous air pollutants (HAPs), as well as data on particle size distribution to support PM-10 emission inventory efforts. Emissions of carbon monoxide (CO_2) are also being considered because of its possible participation in global climatic change and the corresponding interest in including this gas in emission inventories. Most of the carbon in fossil fuels is emitted as CO_2 during combustion. Minor amounts of carbon are emitted as CO, much of which ultimately oxidizes to CO_2, or as carbon in the ash. Finally, fugitive emissions associated with the use of oil at the combustion source are being included in this section.

Tables 1.3-1 through 1.3-4 present emission factors for uncontrolled emissions of criteria pollutants from fuel oil combustion. A general discussion of emissions of criteria and non-criteria pollutants from coal combustion is given in the following paragraphs. Tables 1.3-5 through 1.3-8 present cumulative size distribution data and size specific emission factors for particulate emissions from fuel oil combustion. Uncontrolled and controlled size specific emission factors are presented in Figures 1.3-1 through 1.3-4. Distillate and residual oil categories are given separately, because their combustion produces significantly different particulate, SO_2, and NO_x emissions.

Particulate Matter Emissions[3-7,12-13,21,23-24]

Particulate matter emissions depend predominantly on the grade of fuel fired. Combustion of lighter distillate oils results in significantly lower PM formation than does combustion of heavier residual oils. Among residual oils, firing of Nos. 4 or 5 oils usually produces less PM than does the firing of heavier No. 6 oil.

In general, PM emissions depend on the completeness of combustion as well as on the oil ash content. The PM emitted by distillate oil-fired boilers is primarily carbonaceous particles resulting from incomplete combustion of oil and is not correlated to the ash or sulfur content of the oil. However, PM emissions from residual oil burning is related to the oil sulfur content. This is because low sulfur No. 6 oil, either refined from naturally low sulfur crude oil or desulfurized by one of several processes, exhibits substantially lower viscosity and reduced asphaltene, ash, and sulfur contents, which results in better atomization and more complete combustion.

Boiler load can also affect particulate emissions in units firing No. 6 oil. At low load conditions, particulate emissions from utility boilers may be lowered by 30 to 40 percent and by as much as 60 percent from small industrial and commercial units. However, no significant particulate emissions reductions have been noted at low loads from boilers firing any of the lighter grades. At very low load conditions, proper combustion conditions may be difficult to maintain and particulate emissions may increase significantly.

Sulfur Oxide Emissions[1-6,22]

Sulfur oxide (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 predominantly 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 sulfur trioxide (SO_3); and about 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.

Nitrogen Oxides Emissions[1-11,14,15,20,24-25,28-29,41]

Oxides of nitrogen (NO_x) formed in combustion processes are due either to thermal fixation of atmospheric nitrogen in the combustion air ("thermal NO_x"), or to the conversion of chemically bound nitrogen in the fuel ("fuel NO_x"). The term NO_x refers to the composite of nitric oxide (NO) and nitrogen dioxide (NO_2). Nitrous oxide is not included in NO_x but has taken on recent interest because of atmospheric effects. Test data have shown that for most external fossil fuel combustion systems, over 95 percent of the emitted NO_x is in the form of NO.

Experimental measurements of thermal NO_x formation have shown that NO_x concentration is exponentially dependent on temperature, and proportional to N_2 concentration in the flame, the square root of O_2 concentration in the flame, and the residence time. Thus, the formation of thermal NO_x is affected by four factors: (1) peak temperature, (2) fuel nitrogen concentration, (3) oxygen concentration, and (4) time of exposure at peak temperature. The emission trends due to changes in these factors are generally consistent for all types of boilers: an increase in flame temperature, oxygen availability, and/or residence time at high temperatures leads to an increase in NO_x production.

Fuel nitrogen conversion is the more important NO_x-forming mechanism in residual oil boilers. It can account for 50 percent of the total NO_x emissions from residual oil firing. The percent conversion of fuel nitrogen to NO_x varies greatly, however; typically from 20 to 90 percent of nitrogen in oil is converted to NO_x. Except in certain large units having unusually high peak flame temperatures, or in units firing a low nitrogen content residual oil, fuel NO_x generally accounts for over 50 percent of the total NO_x generated. Thermal fixation, on the other hand, is the dominant NO_x forming mechanism in units firing distillate oils, primarily because of the negligible nitrogen content in these lighter oils. Because distillate oil-fired boilers usually have lower heat release rates, the quantity of thermal NO_x formed in them is less than that of larger units.

A number of variables influence how much NO_x is formed by these two mechanisms. One important variable is firing configuration. NO_x emissions from tangentially (corner) fired boilers are, on the average, less than those of horizontally opposed units. Also important are the firing practices employed during boiler operation. Low excess air (LEA) firing, flue gas recirculation (FGR), staged combustion (SC), reduced air preheat (RAP), low NO_x burners (LNBs), or some combination thereof may result in NO_x reductions of 5 to 60 percent. Load reduction (LR) can likewise decrease NO_x production. Nitrogen oxides emissions may be reduced from 0.5 to 1 percent for each percentage reduction in load from full load operation. It should be noted that most of these variables, with the exception of excess air, influence the NO_x emissions only of large oil fired boilers. Low excess air-firing is possible in many small boilers, but the resulting NO_x reductions are less significant.

Recent N_2O emissions data indicate that direct N_2O emissions from oil combustion units are considerably below the measurements made prior to 1988. Nevertheless, the N_2O formation and reaction mechanisms are still not well understood or well characterized. Additional sampling and research is needed to fully characterize N_2O emissions and to understand the N_2O formation mechanism. Emissions can vary widely from unit to unit, or even from the same unit at different operating conditions. It has been shown in some cases that N_2O increases with decreasing boiler temperature. For this update, average emission factors based on reported test data have been developed for conventional oil combustion systems. These factors are presented in Table 1.3-9.

The new source performance standards (NSPS) for PM, SO_2, and NO_x emissions from residual oil combustion in fossil fuel-fired boilers are shown in Table 1.3-10.

Carbon Monoxide Emissions[16-19]

The rate of CO emissions from combustion sources depends on the oxidation efficiency of the fuel. By controlling the combustion process carefully, CO emissions can be minimized. Thus if a unit is operated improperly or not well maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces tend to emit more of these pollutants than larger combustors. This is because smaller units usually have a higher ratio of heat transfer surface area to flame volume leading to reduced flame temperature and combustion intensity and, therefore, lower combustion efficiency than larger combustors.

The presence of CO in the exhaust gases of combustion systems results principally from incomplete fuel combustion. Several conditions can lead to incomplete combustion, including:

- insufficient oxygen (O_2) availability;
- poor fuel/air mixing;

- cold wall flame quenching;
- reduced combustion temperature;
- decreased combustion gas residence time; and
- load reduction (i.e., reduced combustion intensity).

Since various combustion modifications for NO_x reduction can produce one or more of the above conditions, the possibility of increased CO emissions is a concern for environmental, energy efficiency, and operational reasons.

Organic Compound Emissions[16-19,30-35,64]

Small amounts of organic compounds are emitted from combustion. As with CO emissions, the rate at which organic compounds are emitted depends, to some extent, on the combustion efficiency of the boiler. Therefore, any combustion modification which reduces the combustion efficiency will most likely increase the concentrations of organic compounds in the flue gases.

Total organic compounds (TOCs) include VOCs, semi-volatile organic compounds, and condensible organic compounds. Emissions of VOCs are primarily characterized by the criteria pollutant class of unburned vapor phase hydrocarbons. Unburned hydrocarbon emissions can include essentially all vapor phase organic compounds emitted from a combustion source. These are primarily emissions of aliphatic, oxygenated, and low molecular weight aromatic compounds which exist in the vapor phase at flue gas temperatures. These emissions include all alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene).

The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called polynuclear aromatic hydrocarbons (PNA or PAH). There are also PAH-nitrogen analogs. Information available in the literature on POM compounds generally pertains to these PAH groups.

Formaldehyde is formed and emitted during combustion of hydrocarbon-based fuels including coal and oil. Formaldehyde is present in the vapor phase of the flue gas. Formaldehyde is subject to oxidation and decomposition at the high temperatures encountered during combustion. Thus, larger units with efficient combustion (resulting from closely regulated air-fuel ratios, uniformly high combustion chamber temperatures, and relatively long gas retention times) have lower formaldehyde emission rates than do smaller, less efficient combustion units. Average emission factors for POM and formaldehyde from fuel oil combustors are presented in Table 1.3-9, together with N_2O emissions data.

Trace Element Emissions[16-19, 36-40]

Trace elements are also emitted from the combustion of oil. For this update of AP-42, trace metals included in the list of 189 hazardous air pollutants under Title III of the 1990 Clean Air Act Amendments are considered. The quantity of trace metals emitted depends on combustion temperature, fuel feed mechanism, and the composition of the fuel. The temperature determines the degree of volatilization of specific compounds contained in the fuel. The fuel feed mechanism affects the separation of emissions into bottom ash and fly ash.

The quantity of any given metal emitted, in general, depends on:

- the physical and chemical properties of the element itself;
- its concentration in the fuel;
- the combustion conditions; and
- the type of particulate control device used, and its collection efficiency as a function of particle size.

It has become widely recognized that some trace metals concentrate in certain waste particle streams from a combustor (bottom ash, collector ash, flue gas particulate), while others do not. Various classification schemes have been developed to describe this partitioning have been developed. The classification scheme used by Baig, et al. is as follows:

- Class 1: Elements which are approximately equally distributed between fly ash and bottom ash, or show little or no small particle enrichment.
- Class 2: Elements which are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size.
- Class 3: Elements which are intermediate between Classed 1 and 2.
- Class 4: Elements which are emitted in the gas phase.

By understanding trace metal partitioning and concentration in fine particulate, it is possible to postulate the effects of combustion controls on incremental trace metal emissions. For example, several NO_x controls for boilers reduce peak flame temperatures (e.g., SC, FGR, RAP, and LR). If combustion temperatures are reduced, fewer Class 2 metals will initially volatilize, and fewer will be available for subsequent condensation and enrichment on fine PM. Therefore, for combustors with particulate controls, lowered volatile metal emissions should result due to improved particulate removal. Flue gas emissions of Class 1 metals (the non-segregating trace metals) should remain relatively unchanged.

Lower local O_2 concentration are also expected to affect segregating metal emissions from boilers with particle controls. Lower O_2 availability decreases the possibility of volatile metal oxidation to less volatile oxides. Under these conditions, Class 2 metals should remain in the vapor phase as they enter the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, Class 1 metal emissions should remain unchanged.

Other combustion NO_x controls which decrease local O_2 concentrations (e.g., SC and FGR) also reduce peak flame temperatures. Under these conditions, the effect of reduced combustion temperature is expected to be stronger than that of lower O_2 concentrations. Available trace metals emissions data for fuel oil combustion in boilers are summarized in Table 1.3-11.

1.3.3 Controls

The various control techniques and/or devices employed on oil combustion sources depend on the source category and the pollutant being controlled. Only controls for criteria pollutants are

discussed here because controls for non-criteria emissions have not been demonstrated or commercialized for oil combustion sources.

Control techniques may be classified into three broad categories: fuel substitution, combustion modification, and post combustion control. Fuel substitution involves using "cleaner" fuels to reduce emissions. Combustion modification and post- combustion control are both applicable and widely commercialized for oil combustion sources. Combustion modification is applied primarily for NO_x control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Post-combustion control is applied to emissions of particulate matter, SO_2, and, to some extent, NO_x, from oil combustion.

1.3.3.1 Fuel Substitution[3,5,12,56]

Fuel substitution, or the firing of "cleaner" fuel oils, can substantially reduce emissions of a number of pollutants. Lower sulfur oils, for instance, will reduce SO_x emissions in all boilers, regardless of the size or type of boiler or grade of oil fired. Particulates generally will be reduced when a lighter grade of oil is fired. Nitrogen oxide emissions will be reduced by switching to either a distillate oil or a residual oil with less nitrogen. The practice of fuel substitution, however, may be limited by the ability of a given operation to fire a better grade of oil and by the cost and availability of that fuel.

1.3.3.2 Combustion Modification[1-4,8-9,13-14,20]

Combustion modification includes any physical change in the boiler apparatus itself or in its operation. Regular maintenance of the burner system, for example, is important to assure proper atomization and subsequent minimization of any unburned combustibles. Periodic tuning is important in small units for maximum operating efficiency and emissions control, particularly for PM and CO emissions. Combustion modifications, such as LEA, FGR, SC, and reduced load operation, result in lowered NO_x emissions in large facilities.

Particulate Matter Control[56]

Control of PM emissions from residential and commercial units is accomplished by improved burner servicing and by incorporating appropriate equipment design changes to improve oil atomization and combustion aerodynamics. Optimization of combustion aerodynamics using a flame retention device, swirl, and/or recirculation is considered to be the best approach toward achieving the triple goals of low PM emissions, low NO_x emissions, and high thermal efficiency.

Large industrial and utility boilers are generally well-designed and well-maintained so that soot and condensible organic compound emissions are minimized. Particulate matter emissions are more a result of entrained fly ash in such units. Therefore, post- combustion controls are necessary to reduce PM emissions from these sources.

NO_x Control[37,57-60]

In boilers fired on crude oil or residual oil, the control of fuel NO_x is very important in achieving the desired degree of NO_x reduction since, typically, fuel NO_x accounts for 60 to 80 percent of the total NO_x formed. Fuel nitrogen conversion to NO_x is highly dependent on the fuel-to-air ratio in the combustion zone and, in contrast to thermal NO_x formation, is relatively insensitive to small changes in combustion zone temperature. In general, increased mixing of fuel and air increases

nitrogen conversion which, in turn, increases fuel NO_x. Thus, to reduce fuel NO_x formation, the most common combustion modification technique is to suppress combustion air levels below the theoretical amount required for complete combustion. The lack of oxygen creates reducing conditions that, given sufficient time at high temperatures, cause volatile fuel nitrogen to convert to N_2 rather than NO.

In the formation of both thermal and fuel NO_x, all of the above reactions and conversions do not take place at the same time, temperature, or rate. The actual mechanisms for NO_x formation in a specific situation are dependent on the quantity of fuel bound nitrogen, if any, and the temperature and stoichiometry of the flame zone. Although the NO_x formation mechanisms are different, both thermal and fuel NO_x are promoted by rapid mixing of fuel and combustion air. This rate of mixing may itself depend on fuel characteristics such as the atomization quality of liquid fuels. Additionally, thermal NO_x is greatly increased by increased residence time at high temperatures, as mentioned above. Thus, primary combustion modification controls for both thermal and fuel NO_x typically rely on the following control approaches:

- decrease primary flame zone O_2 level by:
  - decreasing overall O_2 level;
  - controlling (delaying) mixing of fuel and air; and
  - use of fuel-rich primary flame zone.
- decrease residence time at high temperatures by:
  - decreasing adiabatic flame temperature through dilution;
  - decreasing combustion intensity;
  - increasing flame cooling; and
  - decreased primary flame zone residence time.

Table 1.3-12 shows the relationship between these control strategies and the combustion modification NO_x control techniques currently in use on boilers firing fuel oil.

1.3.3.3 Post Combustion Control[54-56]

Post combustion control refers to removal of pollutants from combustion flue gases downstream of the combustion zone of the boiler. Flue gas cleaning is usually employed on large oil-fired boilers.

Particulate Matter Control[56]

Large industrial and utility boilers are generally, well-designed and well-maintained. Hence, particulate collectors are usually the only method of controlling PM emissions from these sources. Use of such collectors is described below.

Mechanical collectors, a prevalent type of control device, are primarily useful in controlling particulates generated during soot blowing, during upset conditions, or when a very dirty heavy oil is fired. For these situations, high efficiency cyclonic collectors can achieve up to 85 percent control of particulate. Under normal firing conditions, or when a clean oil is combusted, cyclonic collectors are not nearly so effective because of the high percentage of small particles (less than 3 micrometers in diameter) emitted.

Electrostatic precipitators (ESPs) are commonly used in oil-fired power plants. Older precipitators, usually small, typically remove 40 to 60 percent of the emitted PM. Because of the low ash content of the oil, greater collection efficiency may not be required. Currently, new or rebuilt ESPs can achieve collection efficiencies of up to 90 percent.

Scrubbing systems have also been installed on oil fired boilers to control both sulfur oxides and particulate. These systems can achieve SO_2 removal efficiencies of 90 to 95 percent and particulate control efficiencies of 50 to 60 percent.

NO_x Control[61]

The variety of flue gas treatment NO_x control technologies is nearly as great as combustion modification techniques. Although these technologies differ greatly in cost, complexity, and effectiveness, they all involve the same basic chemical reaction: the combination of NO_x with ammonia (NH_3) to form nitrogen (N_2) and water (H_2O).

In selective catalytic reduction (SCR), the reaction takes place in the presence of a catalyst, improving performance. Non-catalytic systems rely on a direct reaction, usually at higher temperatures, to remove NO_x. Although removal efficiencies are lower, non-catalytic systems are typically less complex and often significantly less costly. Table 1.3-13 presents various catalytic and non-catalytic NO_x-reduction technologies.

SO_2 Control[62-63]

Commercialized post-combustion flue gas desulfurization (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. Flue gas desulfurization 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 are nonregenerable (in which case all waste streams are de-watered and discarded).

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.

To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO_x absorbent medium and can be designed to remove greater than 90 percent of the incoming SO_x. 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 operating variables. Table 1.3-14 summarizes commercially available post combustion SO_2 control technologies.

TABLE 1.3-1 (METRIC UNITS). CRITERIA POLLUTANT EMISSION FACTORS FOR UNCONTROLLED FUEL OIL COMBUSTION

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e,f]		Filterable PM[g]	
	Emission Factor $kg/10^3$ ℓ	Rating	Emission Factor $kg/10^3$ ℓ	Rating	Emission Factor $kg/10^3$ ℓ	Rating	Emission Factor $kg/10^3$ ℓ	Rating	Emission Factor $kg/10^3$ ℓ	Rating
Utility boilers										
No. 6 oil fired, normal firing (10100401)	19S	A	0.69S	C	8	A	0.6	A	h	A
No. 6 oil fired, tangential firing (10100404)	19S	A	0.69S	C	5	A	0.6	A	h	A
No. 5 oil fired, normal firing (10100405)	19S	A	0.69S	C	8	A	0.6	A	h	B
No. 5 oil fired, tangential firing (10100406)	19S	A	0.69S	C	5	A	0.6	A	h	B
No. 4 oil fired, normal firing (10100504)	18S	A	0.69S	C	8	A	0.6	A	h	B
No. 4 oil fired, tangential firing (10100505)	18S	A	0.69S	C	5	A	0.6	A	h	B
Industrial boilers										
No. 6 oil fired (102004-01/02/03)	19S	A	0.24S	A	0.6	A	0.6	A	h	A
No. 5 oil fired (10200404)	19S	A	0.24S	A	0.6	A	0.6	A	h	B

TABLE 1.3-1 (METRIC UNITS). CRITERIA POLLUTANT EMISSION FACTORS FOR UNCONTROLLED FUEL OIL COMBUSTION
(Continued)

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e,f]		Filterable PM[g]	
	Emission Factor kg/10^3 ℓ	Rating	Emission Factor kg/10^3 ℓ	Rating	Emission Factor kg/10^3 ℓ	Rating	Emission Factor kg/10^3 ℓ	Rating	Emission Factor kg/10^3 ℓ	Rating
Distillate oil fired (102005-01/02/03)	17S	A	0.24S	A	2.4	A	0.6	A	h	A
No. 4 oil fired (10200504)	18S	A	0.24S	A	2.4	A	0.6	A	h	B
Commercial/institutional/residential combustors										
No. 6 oil fired (103004-01/02/03)	19S	A	0.24S	A	0.6	A	0.6	A	h	A
No. 5 oil fired (10300404)	19S	A	0.24S	A	0.6	A	0.6	A	h	B
Distillate oil fired (103005-01/02/03)	17S	A	0.24S	A	2.4	A	0.6	A	h	A
No. 4 oil fired (10300504)	18S	A	0.24S	A	2.4	A	0.6	A	h	B
Residential furnace (No SCC)	17S	A	0.24S	A	2.2	A	0.6	A	0.3	A

[a]SCC = Source Classification Code.
[b]References 1-6, 23, 42-46. S indicates that the weight % of sulfur in the oil should be multiplied by the value given.
[c]References 1-5, 45-46, 22.
[d]References 3-4, 10, 15, 24, 42-46, 48-49. Expressed as NO_2. Test results indicate that at lease 95 % by weight of NO_x is NO for all boiler types except residential furnaces, where about 75 % is NO. For utility vertical fired boilers use 12.6 kg/10^3 ℓ at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: kg NO_2 /10^3 ℓ = 2.465 + 12.526(N) where N is the weight percent of nitrogen in the oil.
[e]References 3-5, 8-10, 23, 42-46, 48. CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

TABLE 1.3-1 (METRIC UNITS). CRITERIA POLLUTANT EMISSION FACTORS FOR UNCONTROLLED FUEL OIL COMBUSTION
(Continued)

[f]Emission factor for CO_2 from oil combustion should be calculated using kg $CO_2/10^3$ ℓ oil = 31.0 C (distillate) or 34.6 C (residual).

[g]References 3-5, 7, 21, 23-24, 42-46, 47, 49. Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. PM-10 values include that particulate collected in the PM-10 filter cyclone of an EPA Method 201 or 201A sampling train.

[h]Particulate emission factors for residual oil combustion are, on average, a function of fuel oil grade and sulfur content:

No. 6 oil:1.12(S) + 0.37 kg/10^3 ℓ where S is the weight % of sulfur in oil.

No. 5 oil:1.2 kg/10^3 ℓ

No. 4 oil:0.84 kg/10^3 ℓ

No. 2 oil:0.24 kg/10^3 ℓ

TABLE 1.3-2 (ENGLISH UNITS). CRITERIA POLLUTANT EMISSION FACTORS FOR UNCONTROLLED FUEL OIL COMBUSTION

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e,f]		Filterable PM[g]	
	Emission Factor lb/10^3 gal	Rating	Emission Factor lb/10^3 gal	Rating	Emission Factor lb/10^3 gal	Rating	Emission Factor lb/10^3 gal	Rating	Emission Factor lb/10^3 gal	Rating
Utility boilers										
No. 6 oil fired, normal firing (10100401)	157S	A	5.7S	C	67	A	5	A	h	A
No. 6 oil fired, tangential firing (10100404)	157S	A	5.7S	C	42	A	5	A	h	A
No. 5 oil fired, normal firing (10100405)	157S	A	5.7S	C	67	A	5	A	h	B
No. 5 oil fired, tangential firing (10100406)	157S	A	5.7S	C	42	A	5	A	h	B
No. 4 oil fired, normal firing (10100504)	150S	A	5.7S	C	67	A	5	A	h	B
No. 4 oil fired, tangential firing (10100505)	150S	A	5.7S	C	42	A	5	A	h	B
Industrial boiler										
No. 6 oil fired (102004-01/02/03)	157S	A	2S	A	55	A	5	A	h	A
No. 5 oil fired (10200404)	157S	A	2S	A	55	A	5	A	h	B

TABLE 1.3-2 (ENGLISH UNITS). CRITERIA POLLUTANT EMISSION FACTORS FOR UNCONTROLLED FUEL OIL COMBUSTION
(Continued)

Firing Configuration (SCC)[a]	SO_2[b]		SO_3[c]		NO_x[d]		CO[e,f]		Filterable PM[g]	
	Emission Factor lb/10^3 gal	Rating	Emission Factor lb/10^3 gal	Rating	Emission Factor lb/10^3 gal	Rating	Emission Factor lb/10^3 gal	Rating	Emission Factor lb/10^3 gal	Rating
Distillate oil fired (102005-01/02/03)	142S	A	2S	A	20	A	5	A	h	A
No. 4 oil fired (10200504)	150S	A	2S	A	20	A	5	A	h	B
Commercial/institutional/residential combustors										
No. 6 oil fired (103004-01/02/03)	157S	A	2S	A	55	A	5	A	h	A
No. 5 oil fired (10300404)	157S	A	2S	A	55	A	5	A	h	B
Distillate oil fired (103005-01/02/03)	142S	A	2S	A	20	A	5	A	h	A
No. 4 oil fired (10300504)	150S	A	2S	A	20	A	5	A	h	B
Residential furnace (No SCC)	142S	A	2S	A	18	A	5	A	0.3	A

[a]SCC = Source Classification Code.
[b]References 1-6, 23, 42-46. S indicates that the weight % of sulfur in the oil should be multiplied by the value given.
[c]References 1-5, 45-46, 22.
[d]References 3-4, 10, 15, 24, 42-46, 48-49. Expressed as NO_2. Test results indicate that at lease 95 % by weight of NO_x is NO for all boiler types except residential furnaces, where about 75 % is NO. For utility vertical fired boilers use 105 lb/10^3 gal at full load and normal (>15%) excess air. Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are related to fuel nitrogen content, estimated by the following empirical relationship: lb NO_2 /10^3 gal = 20.54 + 104.39(N) where N is the weight percent of nitrogen in the oil.

TABLE 1.3-2 (ENGLISH UNITS). CRITERIA POLLUTANT EMISSION FACTORS FOR UNCONTROLLED FUEL OIL COMBUSTION
(Continued)

[e]References 3-5, 8-10, 23, 42-46, 48. CO emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

[f]Emission factor for CO_2 from oil combustion should be calculated using lb $CO_2/10^3$ gal oil = 259 C (distillate) or 288 C (residual).

[g]References 3-5, 7, 21, 23-24, 42-46, 47, 49. Filterable PM is that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. PM-10 values include that particulate collected in the PM-10 filter cyclone of an EPA Method 201 or 201A sampling train.

[h]Particulate emission factors for residual oil combustion are, on average, a function of fuel oil grade and sulfur content:

No. 6 oil:9.19(S) + 3.22 lb/10^3 gal where S is the weight % of sulfur in oil

No. 5 oil:10 lb/10^3 gal

No. 4 oil:7 lb/10^3 gal

No. 2 oil:2 lb/10^3 gal

TABLE 1.3-3 (METRIC UNITS). EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION

Firing Configuration (SCC)[a]	TOC[b]		Methane[b]		NMTOC[b]	
	Emission Factor kg/10^3 ℓ	Rating	Emission Factor kg/10^3 ℓ	Rating	Emission Factor kg/10^3 ℓ	Rating
Utility boilers						
No. 6 oil fired, normal firing (10100401)	0.125	A	0.034	A	0.091	A
No. 6 oil fired, tangential firing (10100404)	0.125	A	0.034	A	0.091	A
No. 5 oil fired, normal firing (10100405)	0.125	A	0.034	A	0.091	A
No. 5 oil fired, tangential firing (10100406)	0.125	A	0.034	A	0.091	A
No. 4 oil fired, normal firing (10100504)	0.125	A	0.034	A	0.091	A
No. 4 oil fired, tangential firing (10100505)	0.125	A	0.034	A	0.091	A
Industrial boilers						
No. 6 oil fired (102004-01/02/03)	0.154	A	0.12	A	0.034	A
No. 5 oil fired (10200404)	0.154	A	0.12	A	0.034	A
Distillate oil fired (102005-01/02/03)	0.030	A	0.006	A	0.024	A
No. 4 oil fired (10200504)	0.030	A	0.006	A	0.024	A
Commercial/institutional/residential combustors						
No. 6 oil fired (103004-01/02/03)	0.193	A	0.057	A	0.136	A
No. 5 oil fired (10300404)	0.193	A	0.057	A	0.136	A

TABLE 1.3-3 (METRIC UNITS). EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION (Continued)

Firing Configuration (SCC)[a]	TOC[b]		Methane[b]		NMTOC[b]	
	Emission Factor kg/10^3 ℓ	Rating	Emission Factor kg/10^3 ℓ	Rating	Emission Factor kg/10^3 ℓ	Rating
Distillate oil fired (103005-01/02/03)	0.067	A	0.026	A	0.041	A
No. 4 oil fired (10300504)	0.067	A	0.026	A	0.041	A
Residential furnace (No SCC)	0.299	A	0.214	A	0.085	A

[a]SCC = Source Classification Code.
[b]References 16-19. Volatile organic compound emission can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

TABLE 1.3-4 (ENGLISH UNITS). EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION

Firing Configuration (SCC)[a]	TOC[b]		Methane[b]		NMTOC[b]	
	Emission Factor lb/10^3 gal	Rating	Emission Factor lb/10^3 gal	Rating	Emission Factor lb/10^3 gal	Rating
Utility boilers						
No. 6 oil fired, normal firing (10100401)	1.04	A	0.28	A	0.76	A
No. 6 oil fired, tangential firing (10100404)	1.04	A	0.28	A	0.76	A
No. 5 oil fired, normal firing (10100405)	1.04	A	0.28	A	0.76	A
No. 5 oil fired, tangential firing (10100406)	1.04	A	0.28	A	0.76	A
No. 4 oil fired, normal firing (10100504)	1.04	A	0.28	A	0.76	A
No. 4 oil fired, tangential firing (10100505)	1.04	A	0.28	A	0.76	A
Industrial boilers						
No. 6 oil fired (102004-01/02/03)	1.28	A	1	A	0.28	A
No. 5 oil fired (10200404)	1.28	A	1	A	0.28	A
Distillate oil fired (102005-01/02/03)	0.252	A	0.052	A	0.2	A
No. 4 oil fired (10200504)	0.252	A	0.052	A	0.2	A
Commercial/institutional/residential combustors						
No. 6 oil fired (103004-01/02/03)	1.605	A	0.475	A	1.13	A
No. 5 oil fired (10300404)	1.605	A	0.475	A	1.13	A

TABLE 1.3-4 (ENGLISH UNITS). EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), METHANE, AND NONMETHANE TOC (NMTOC) FROM UNCONTROLLED FUEL OIL COMBUSTION (Continued)

Firing Configuration (SCC)[a]	TOC[b]		Methane[b]		NMTOC[b]	
	Emission Factor lb/10^3 gal	Rating	Emission Factor lb/10^3 gal	Rating	Emission Factor lb/10^3 gal	Rating
Distillate oil fired (103005-01/02/03)	0.556	A	0.216	A	0.34	A
No. 4 oil fired (10300504)	0.556	A	0.216	A	0.34	A
Residential furnace (No SCC)	2.493	A	1.78	A	0.713	A

[a]SCC = Source Classification Code.
[b]References 16-19. Volatile organic compound emission can increase by several orders of magnitude if the boiler is improperly operated or is not well maintained.

TABLE 1.3-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR UTILITY BOILERS FIRING RESIDUAL OIL[a]

Particle Size[b] (μm)	Cumulative Mass % ≤ stated size			Cumulative Emission Factor, [kg/10^3 ℓ (lb/10^3 gal)]					
	Uncontrolled	Controlled		Uncontrolled[c]		ESP Controlled[d]		Scrubber Controlled[e]	
		ESP	Scrubber	Factor	Rating	Factor	Rating	Factor	Rating
15	80	75	100	0.80A (6.7A)	C	0.0060A (0.05A)	E	0.06A (0.50A)	D
10	71	63	100	0.71A (5.9A)	C	0.005A (0.042A)	E	0.06A (0.050A)	D
6	58	52	100	0.58A (4.8A)	C	0.0042A (0.035A)	E	0.06A (0.50A)	D
2.5	52	41	97	0.52A (4.3A)	C	0.0033A (0.028A)	E	0.058A (0.48A)	D
1.25	43	31	91	0.43A (3.6A)	C	0.0025A (0.021A)	E	0.055A (0.46A)	D
1.00	39	28	84	0.39A (3.3A)	C	0.0022A (0.018A)	E	0.050A (0.42A)	D
0.625	20	10	64	0.20A (1.7A)	C	0.0008A (0.007A)	E	0.038A (0.32A)	D
TOTAL	100	100	100	1A (8.3A)	C	0.008A (0.067A)	E	0.06A (0.50A)	

[a]Reference 29. ESP = electrostatic precipitator. Source Classification Codes: 101004-01/04/05/06, 101005-04/05.
[b]Expressed as aerodynamic equivalent diameter.
[c]Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content:
No. 6 oil: $A = 1.12(S) + 0.37$ kg/10^3 ℓ Where S is the weight % of sulfur in the oil
No. 5 oil: $A = 1.2$ kg/10^3 ℓ
No. 4 oil: $A = 0.84$ kg/10^3 ℓ
[d]Estimated control efficiency for scrubber is 94%.
[e]Estimated control efficiency for ESP is 99.2%.

TABLE 1.3-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR INDUSTRIAL BOILERS FIRING RESIDUAL OIL[a]

Particle Size[b] (μm)	Cumulative Mass % ≤ stated size		Cumulative Emission Factor[c], [Kg/10^3 l (lb/10^3 gal)]			
	Uncontrolled	Multiple Cyclone Controlled	Uncontrolled		Multiple Cyclone Controlled[e]	
			Factor	Rating	Factor	Rating
15	91	100	0.91A (7.59A)	D	0.20A (1.67A)	E
10	86	95	0.86A (7.17A)	D	0.19A (1.58A)	E
6	77	72	0.77A (6.42A)	D	0.14A (1.17A)	E
2.5	56	22	0.56A (4.67A)	D	0.04A (0.33A)	E
1.25	39	21	0.39A (3.25A)	D	0.04A (0.33A)	E
1.00	36	21	0.36A (3.00A)	D	0.04A (0.33A)	E
0.625	30	d	0.30A (2.50A)	D	d	
TOTAL	100	100	1A (8.34A)	D	0.2A (1.67A)	E

[a]Reference 29. Source Classification Codes: 102004-01/02/03/04, 10200504.
[b]Expressed as aerodynamic equivalent diameter.
[c]Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content:
No. 6 oil: $A = 1.12(S) + 0.38$ kg/10^3 ℓ Where S is the weight % of sulfur in the oil
No. 5 oil: $A = 1.2$ kg/10^3 ℓ
No. 4 oil: $A = 0.84$ kg/10^3 ℓ
[d]Insufficient data.
[e]Estimated control efficiency for multiple cyclone is 80%.

TABLE 1.3-7. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR UNCONTROLLED INDUSTRIAL BOILERS FIRING DISTILLATE OIL[a]

EMISSION FACTOR RATING: E

Particle Size[b] (μm)	Cumulative Mass % ≤ stated size	Cumulative Emission Factor, [kg/10^3 ℓ (lb/10^3 gal)]
	Uncontrolled	Uncontrolled
15	68	0.16 (1.33)
10	50	0.12 (1.00)
6	30	0.07 (0.58)
2.5	12	0.03 (0.25)
1.25	9	0.02 (0.17)
1.00	8	0.02 (0.17)
0.625	2	0.005 (0.04)
TOTAL	100	0.24 (2.00)

[a]Reference 29. Source Classification Codes: 102005-01/02/03.
[b]Expressed as aerodynamic equivalent diameter.

TABLE 1.3-8. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR UNCONTROLLED COMMERCIAL BOILERS BURNING RESIDUAL AND DISTILLATE OIL[a]

EMISSION FACTOR RATING: D

Particle Size[b] (μm)	Cumulative Mass % ≤ stated size		Cumulative Emission Factor,[c] [kg/10^3 ℓ (lb/10^3 gal)]	
	Uncontrolled, Residual Oil	Uncontrolled, Distillate Oil	Uncontrolled, Residual Oil	Uncontrolled, Distillate Oil
15	78	60	0.78A (6.50A)	0.14 (1.17)
10	62	55	0.62A (5.17A)	0.13 (1.08)
6	44	49	0.44A (3.67A)	0.12 (1.00)
2.5	23	42	0.23A (1.92A)	0.10 (0.83)
1.25	16	38	0.16A (1.33A)	0.09 (0.75)
1.00	14	37	0.14A (1.17A)	0.09 (0.75)
0.625	13	35	0.13A (1.08A)	0.08 (0.67)
TOTAL	100	100	1A (8.34A)	0.24 (2.00)

[a]Reference 29. Source Classification Codes: 103004-01/02/03/04,103005-01/02/03/04.
[b]Expressed as aerodynamic equivalent diameter.
[c]Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content:
No. 6 oil: A = 1.12(S) + 0.37 kg/10^3 ℓ Where S is the weight % of sulfur in the oil
No. 5 oil: A = 1.2 kg/10^3 ℓ
No. 4 oil: A = 0.84 kg/10^3 ℓ
No. 2 oil: A = 0.24 kg/10^3 ℓ

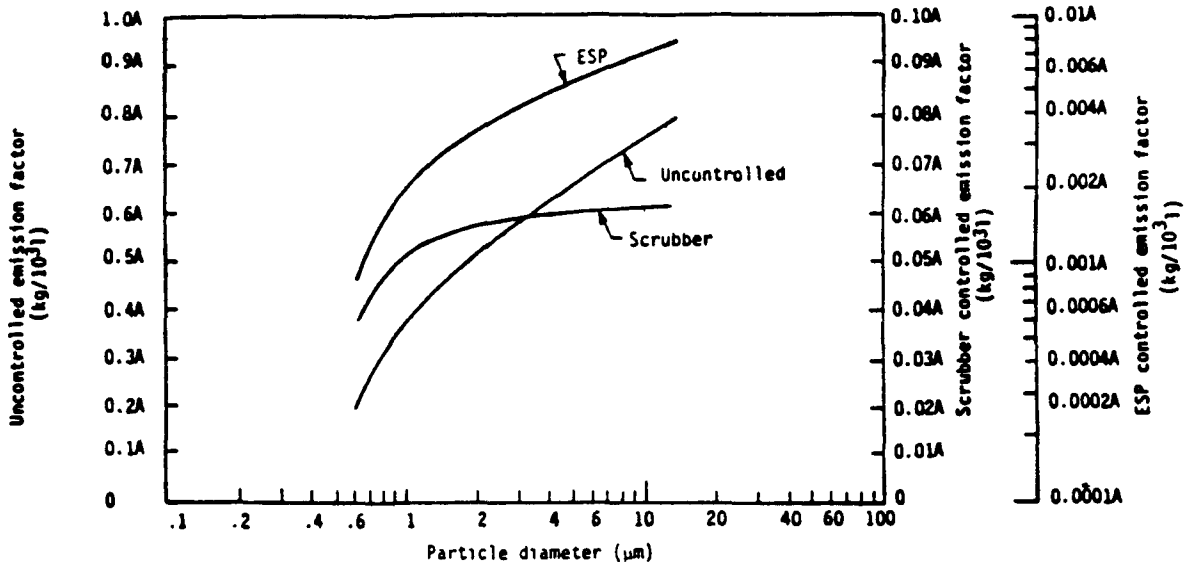


Figure 1.3-1. Cumulative site specific emission factors for utility boilers firing residual oil.

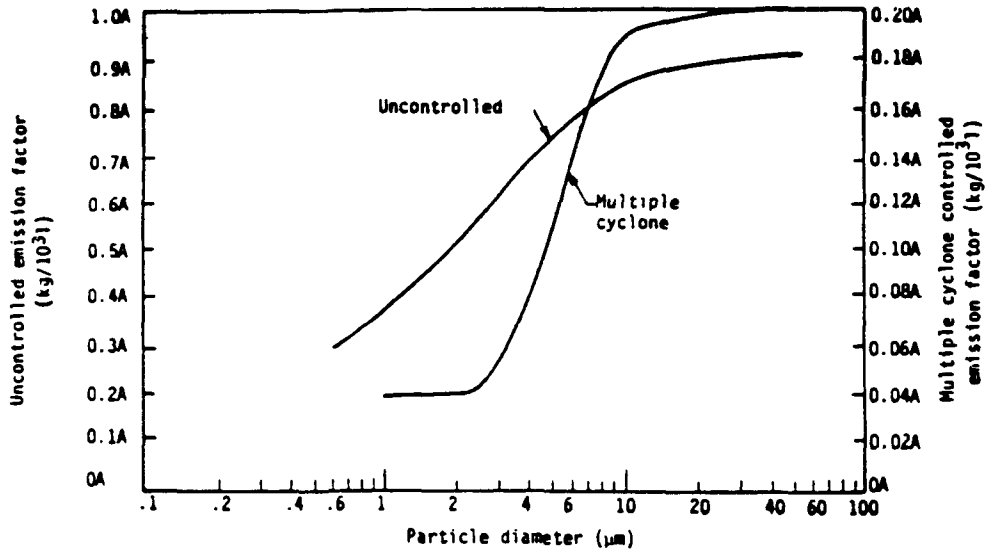


Figure 1.3-2. Cumulative site specific emission factors for industrial boilers firing residual oil.

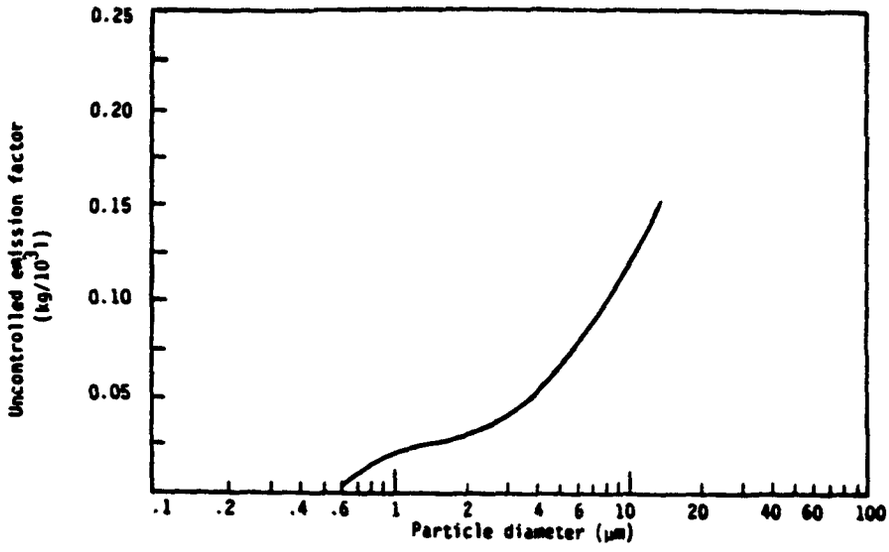


Figure 1.3-3. Cumulative site specific emission factors for uncontrolled industrial boilers firing distillate oil.

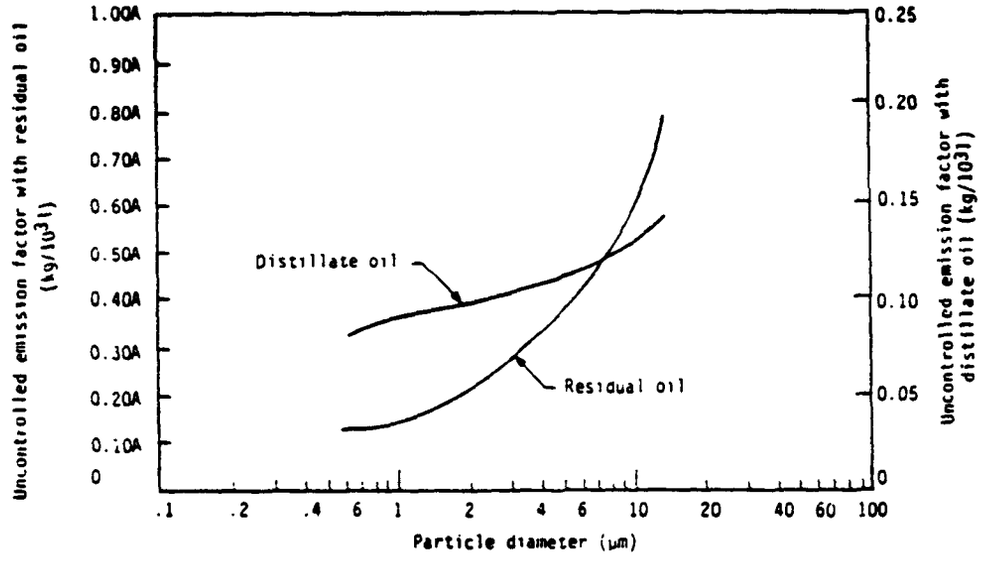


Figure 1.3-4. Cumulative site specific emission factors for uncontrolled commercial boilers burning residual and distillate oil.

TABLE1.3-9. EMISSION FACTORS FOR NITROUS OXIDE (N_2O), POLYCYCLIC ORGANIC MATTER (POM), AND FORMALDEHYDE (HCOH) FROM FUEL OIL COMBUSTION

EMISSION FACTOR RATING: E

Firing Configuration (SCC)[a]	Emission Factor, kg/10^3 ℓ (lb/10^3 gal)		
	N_2O[b]	POM[c]	HCOH[c]
Utility/industrial/commercial boilers			
No. 6 oil fired (101004-01 10200401 10300401)	0.013 (0.11)	3.2-3.6 (7.4-8.4)[d]	69-174 (161-405)
Distillate oil fired (10100501 10200501 10300501)	0.013 (0.11)	9.7 (22)[e]	100-174 (233-405)
Residential furnaces (No SCC)	0.006 (0.05)	NA	NA

[a]SCC = Source Classification Code.
[b]References 28-29.
[c]References 16-19.
[d]Particulate and gaseous POM.
[e]Particulate POM only.
NA = Not available.

TABLE 1.3-10. NEW SOURCE PERFORMANCE STANDARDS FOR FOSSIL FUEL FIRED BOILERS

Standard/ Boiler Types/ Applicability Criteria	Boiler Size MW (Million Btu/hr)	Fuel or Boiler Type	PM ng/J (lb/MMBtu) [% reduction]	SO_2 ng/J (lb/MMBtu) [% reduction]	NO_x ng/J (lb/MMBtu) [% reduction]
Subpart D	>73 (>250)	Gas	43 (0.10)	NA	86 (0.20)
Industrial-Utility		Oil	43 (0.10)	340 (0.80)	129 (0.30)
Commence construction after 8/17/71		Bit./Subbit. Coal	43 (0.10)	520 (1.20)	300 (0.70)
Subpart Da	>73 (>250)	Gas	13 (0.03 [NA]	340 (0.80) [90][a]	86 (020) [25]
Utility					
Commence construction after 9/18/78		Oil	13 (0.03) [70]	340 (0.80) [90][a]	130 (0.30) [30]
		Bit./Subbit. Coal	13 (0.03) [99]	520 (1.20) [90][b]	260/210[c] (0.60/0.50) [65/65]
Subpart Db	>29 (>100)	Gas	NA[d]	NA[d]	43[f] (0.10)
Industrial-Commercial-Institutional		Distillate Oil	43 (0.10)	340[n] (0.80) [90]	43[f] (0.10)
Commence construction after 6/19/84[m]		Residual Oil	(Same as for distillate oil)	(Same as for distillate oil)	130[g] (0.30)
		Pulverized Bit./Subbit. Coal	22[e] (0.05)	520[e] (1.20) [90]	300 (0.70)
		Spreader Stoker & FBC	22[e] (0.05)	520[e] (1.20) [90]	260 (0.60)
		Mass-Feed Stoker	22[e] (0.05)	520[e] (1.20) [90]	210 (0.50)

TABLE 1.3-10. NEW SOURCE PERFORMANCE STANDARDS FOR FOSSIL FUEL FIRED BOILERS (Continued)

Standard/ Boiler Types/ Applicability Criteria	Boiler Size MW (Million Btu/hr)	Fuel or Boiler Type	PM ng/J (lb/MMBtu) [% reduction]	SO_2 ng/J (lb/MMBtu) [% reduction]	NO_x ng/J (lb/MMBtu) [% reduction]
Subpart Dc	2.9 - 29 (10 - 100)	Gas	-[h]	-	-
Small Industrial-Commercial-Institutional		Oil	-[h,j]	215 (0.50)	-
Commence construction after 6/9/89		Bit. & Subbit. Coal	22[j,k] (0.05)	520[k] (1.20 [90]	-

[a]Zero percent reduction when emissions are less than 86 ng/J (0.20 lb/MMBtu).
[b]70 percent reduction when emissions are less than 260 ng/J (0.60 lb/MMBtu).
[c]The first number applies to bituminous coal and the second to subbituminous coal.
[d]Standard applies when gas is fired in combination with coal, see 40 CFR 60, Subpart Db.
[e]Standard is adjusted for fuel combinations and capacity factor limits, see 40 CFR 60, Subpart Db.
[f]For furnace heat release rates greater than 730,000 J/s-m^3 (70,000 Btu/hr-ft^3), the standard is 86 ng/J (0.20 lb/MMBtu).
[g]For furnace heat release rates greater than 730,000 J/s-m^3 (70,000 Btu/hr-ft^3), the standard is 170 ng/J (0.40 lb/MMBtu).
[h]Standard applies when gas or oil is fired in combination with coal, see 40 CFR 60, Subpart Dc.
[j]20 percent capacity limit applies for heat input capacities of 8.7 Mwt (30 MMBtu/hr) or greater.
[k]Standard is adjusted for fuel combinations and capacity factor limits, see 40 CFR 60, Subpart Dc.
[m]Additional requirements apply to facilities which commenced construction, modification, or reconstruction after 6/19/84 but on or before 6/19/86 (see 40 Code of Federal Regulations Part 60, Subpart Db).
[n]215 ng/J (0.50 lb/million Btu) limit (but no percent reduction requirement) applies if facilities combust only very low sulfur oil (< 0.5 wt. % sulfur).
FBC = Fluidized bed combustion.

TABLE 1.3-11. EMISSION FACTORS FOR TRACE ELEMENTS FROM FUEL OIL COMBUSTION SOURCES

EMISSION FACTOR RATING: E

Firing Configuration (SCC)[a]	Emission Factor, pg/J (lb/10^{12} Btu)[b]										
	Sb	As	Be	Cd	Cr	Co	Pb	Mn	Hg	Ni	Se
No. 6 oil fired (101004-01/04 10200401 10300401)	10-20 (24-46)	8.2-49 (19-114)	1.8 (4.2)	6.8-91 (16-211)	9.0-55 (21-128)	33-50 (77-121)	12-80 (28-194)	10-30 (23-74)	0.6-14 (1.4-32)	360-964 (837-2330)	16 (38)
Distillate oil fired (10100501 10200501 10300501)	NA	1.8 (4.2)	1.1 (2.5)	4.5 (11)	21-29 (48-67)	NA	3.8 (8.9)	6.0 (14)	1.3 (3.0)	7.3 (18)	NA

[a]SCC = Source Classification Code.
[b]References 16-19, 36-40. The emission factors in this table represent the ranges of factors reported in the literature. If only one data point was found, it is still reported in this table.
NA = Not available.

TABLE 1.3-12. COMBUSTION MODIFICATION NO_x CONTROLS FOR OIL FIRED BOILERS

Control Technique	Description of Technique	Effectiveness of Control (Percent NO_x Reduction)		Range of Application	Commercial Availability/ R&D Status	Comments
		Residual Oil	Distillate Oil			
Low Excess Air (LEA)	Reduction of combustion air	0 to 28	0 to 24	Generally excess O_2 can be reduced to 2.5 % representing a 3 % drop from baseline	Available	Added benefits included increase in boiler efficiency. Limited by increase in CO, HC, and smoke emissions.
Staged Combustion (SC)	Fuel-rich firing burners with secondary combustion air ports	20 to 50	17 to 44	70-90 % burner stoichiometries can be used with proper installation of secondary air ports	Technique is applicable on package and field-erected units. However, not commercially available for all design types	Best implemented on new units. Retrofit is probably not feasible for most units, especially packaged ones.
Burners Out of Service (BOOS)	One or more burners on air only. Remainder firing fuel rich.	10 to 30	N/A	Applicable only for boilers with minimum of 4 burners. Best suited for square burner pattern with top burner or burners out of service. Only for retrofit application.	Available. Retrofit requires careful selection of BOOS pattern and control of air flow.	Retrofit often requires boiler de-rating unless fuel delivery system is modified.
Flue Gas Recirculation (FGR)	Recirculation of portion of flue gas to burners	15 to 30	58 to 73	Up to 25-30% of flue gas recycled. Can be implemented on all design types.	Available. Requires extensive modifications to the burner and windbox.	Best suited for new units. Costly to retrofit. Possible flame instability at high FGR rates.
Flue Gas Recirculation Plus Staged Combustion	Combined techniques of FGR and staged combustion	25 to 53	73 to 77	Max. FGR rates set at 25% for distillate oil and 20% for residual oil	Combined techniques are still at experimental stage.	Retrofit may not be feasible. Best implemented on new units.

TABLE 1.3-12. COMBUSTION MODIFICATION NO_x CONTROLS FOR OIL FIRED BOILERS (Continued)

Control Technique	Description of Technique	Effectiveness of Control (Percent NO_x Reduction)		Range of Application	Commercial Availability/ R&D Status	Comments
		Residual Oil	Distillate Oil			
Load Reduction (LR)	Reduction of air and fuel flow to all burners in service	33% decrease to 25% increase in NO_x	31% decrease to 17% increase in NO_x	Applicable to all boiler types and sizes. Load can be reduced to 25% of maximum.	Available now as a retrofit application. Better implemented with improved firebox design.	Technique not effective when it necessitates an increase in excess O_2 levels. LR possibly implemented in new designs as reduced combustion intensity (enlarged furnace plan area).
Low NO_x Burners (LNB)	New burner designs with controlled air/fuel mixing and increased heat dissipation	20 to 50	20 to 50	New burners described generally applicable to all boilers. More specific information needed.	Commercially offered but not demonstrated	Specific emissions data from industrial boilers equipped with LNB are lacking
Ammonia Injection	Injection of NH_3 as a reducing agent in the flue gas	40 to 70	40 to 70	Applicable for large package and field-erected watertube boilers. May not be feasible for fire-tube boilers.	Commercially offered but not demonstrated	Elaborate NH_3 injection, monitoring and control system required. Possible load restrictions on boiler and air preheater fouling when burning high sulfur oil.
Reduced Air Preheat (RAP)	Bypass of combustion air preheater	5 to 16	N/A	Combustion air temperature can be reduced to ambient conditions (340K)	Available. Not implemented because of significant loss in thermal efficiency.	Application of this technique on new boilers requires installation of alternate heat recovery system (e.g., an economizer)

TABLE 1.3-13. POST-COMBUSTION NO_x REDUCTION TECHNOLOGIES

Technique	Description	Advantages	Disadvantages
1. Urea injection	Injection of urea into furnace to react with NO_x to form N_2 and H_2O	- Low capital cost - Relatively simple system - Moderate NO_x removal (30-60%) - Non-toxic chemical - Typically, low energy injection sufficient	- Temperature dependent - Design must consider boiler operating conditions and design - Reduction may decreased at lower loads
2. Ammonia injection (Thermal-DeNO$_x$)	Injection of ammonia into furnace to react with NO_x to form N_2 and H_2O	- Low operating cost - Moderate NO_x removal (30-60%)	- Moderately high capital cost - Ammonia handling, storage, vaporization and injection systems required (Ammonia is a toxic chemical)
3. Air Heater (AH-)SCR	Air heater baskets replaced with catalyst coated baskets. Catalyst promotes reaction of ammonia with NO_x.	- Moderate NO_x removal (40-65 %) - Moderate capital cost - No additional ductwork or reactor required - Low pressure drop - Can use urea as ammonia feedstock - Rotating air heater assists mixing, contact with catalyst	- Design must address pressure drop, maintain heat transfer - Due to rotation of air heater, only 50% of catalyst is active at any time
4. Duct SCR	A smaller version of conventional SCR is placed in existing ductwork	- Moderate capital cost - Moderate NO_x removal (30%) - No additional ductwork required	- Duct location unit specific temperature, access dependent - Some pressure drop must be accommodated
5. Activated Carbon SCR	Activate carbon catalyst, installed downstream of air heater, promotes reaction of ammonia with NO_x at low temperature.	- Active at low temperature - High surface area reduces reactor size - Low cost of catalyst - Can use urea as ammonia feedstock - Activated carbon is non-hazardous material - SO_x removal as well as NO_x removal	- High pressure drop - Not a fully commercial technology

TABLE 1.3-13. POST-COMBUSTION NO_x REDUCTION TECHNOLOGIES (Continued)

Technique	Description	Advantages	Disadvantages
1. Urea injection	Injection of urea into furnace to react with NO_x to form N_2 and H_2O	- Low capital cost - Relatively simple system - Moderate NO_x removal (30-60%) - Non-toxic chemical - Typically, low energy injection sufficient	- Temperature dependent - Design must consider boiler operating conditions and design - Reduction may decreased at lower loads
6. Conventional SCR	Catalyst located in flue gas stream (usually upstream of air heater) promotes reaction of ammonia with NO_x.	- High NO_x removal (90%)	- Very high capital cost - High operating cost - Extensive ductwork to/from reactor - Large volume reactor must be sited - Increased pressure drop may require ID fan or larger FD fan - Reduced efficiency - Ammonia sulfate removal equipment for air heater - Water treatment of air heater wash

TABLE 1.3-14. POST-COMBUSTION SO_2 CONTROLS FOR FUEL OIL COMBUSTION SOURCES

Control Technology	Process	Typical Control Efficiencies	Remarks
Wet scrubber	Lime/limestone	80-95+%	Applicable to high sulfur fuels, Wet sludge product
	Sodium carbonate	80-98%	1-125 MW (5-430 million Btu/hr) typical application range, High reagent costs
	Magnesium oxide/hydroxide	80-95+%	Can be regenerated
	Dual alkali	90-96%	Uses lime to regenerate sodium-based scrubbing liquor
Spray drying	Calcium hydroxide slurry, vaporizes in spray vessel	70-90%	Applicable to low and medium sulfur fuels, Produces dry product
Furnace injection	Dry calcium carbonate/hydrate injection in upper furnace cavity	25-50%	Commercialized in Europe, Several U.S. demonstration projects underway
Duct injection	Dry sorbent injection into duct, sometimes combined with water spray	25-50+%	Several R&D and demonstration projects underway, Not yet commercially available in the U.S.

References for Section 1.1

1. W.S. Smith, Atmospheric Emissions from Fuel Oil Combustion: An Inventory Guide, 999-AP-2, U.S. Environmental Protection Agency, Washington, DC, November 1962.

2. J.A. Danielson (ed.), Air Pollution Engineering Manual, Second Edition, AP-40, U.S. Environmental Protection Agency, Research Triangle Park, NC, 1973. Out of Print.

3. A. Levy, et al., A Field Investigation of Emissions from Fuel Oil Combustion for Space Heating, API Bulletin 4099, Battelle Columbus Laboratories, Columbia, OH, November 1971.

4. R.E. Barrett, et al., Field Investigation of Emissions from Combustion Equipment for Space Heating, EPA-R2-73-084a, U.S. Environmental Protection Agency, Research Triangle Park, NC, June 1973.

5. G.A. Cato, et al., Field Testing: Application of Combustion Modifications To Control Pollutant Emissions from Industrial Boilers - Phase I, EPA-650/2-74-078a, U.S. Environmental Protection Agency, Washington, DC, October 1974.

6. G.A. Cato, et al., Field Testing: Application of Combustion Modifications To Control Pollutant Emissions from Industrial Boilers - Phase II, EPA-600/ 2-76-086a, U.S. Environmental Protection Agency, Washington, DC, April 1976.

7. Particulate Emission Control Systems for Oil Fired Boilers, EPA-450/3-74- 063, U.S. Environmental Protection Agency, Research Triangle Park, NC, December 1974.

8. W. Bartok, et al., Systematic Field Study of NOx Emission Control Methods for Utility Boilers, APTD-1163, U.S. Environmental Protection Agency, Research Triangle Park, NC, December 1971.

9. A.R. Crawford, et al., Field Testing: Application of Combustion Modifications To Control NOx Emissions from Utility Boilers, EPA-650/2-74-066, U.S. Environmental Protection Agency, Washington, DC, June 1974.

10. J.F. Deffner, et al., Evaluation of Gulf Econojet Equipment with Respect to Air Conservation, Report No. 731RC044, Gulf Research and Development Company, Pittsburgh, PA, December 18, 1972.

11. C.E. Blakeslee and H.E. Burbach, "Controlling NOx Emissions from Steam Generators," Journal of the Air Pollution Control Association, 23:37-42, January 1973.

12. C.W. Siegmund, "Will Desulfurized Fuel Oils Help?," American Society of Heating, Refrigerating and Air Conditioning Engineers Journal, 11:29-33, April 1969.

13. F.A. Govan, et al., "Relationships of Particulate Emissions Versus Partial to Full Load Operations for Utility-sized Boilers," Proceedings of Third Annual Industrial Air Pollution Control Conference, Knoxville, TN, March 29-30, 1973.

14. R.E. Hall, et al., A Study of Air Pollutant Emissions from Residential Heating Systems, EPA-650/2-74-003, U.S. Environmental Protection Agency, Washington, DC, January 1974.

15. R.J. Milligan, et al., Review of. NOx Emission Factors- for Stationary Fossil Fuel Combustion Sources, EPA-450/4-79-021, U.S. Environmental Protection Agency, Research Triangle Park, NC, September 1979.

16. N.F. Suprenant, et al., Emissions Assessment of Conventional Stationary Combustion Systems, Volume I: Gas and Oil Fired Residential Heating Sources, EPA-600/7-79-029b, U.S. Environmental Protection Agency, Washington, DC, May 1979.

17. C.C. Shih, et al., Emissions Assessment of Conventional Stationary Combustion Systems, Volume III: External Combustion Sources for Electricity Generation, EPA Contract No. 68-02-2197, TRW, Inc., Redondo Beach, CA, November 1980.

18. N.F. Suprenant, et al., Emissions Assessment of Conventional Stationary Combustion System, Volume IV: Commercial Institutional Combustion Sources, EPA Contract No. 68-02-2197, GCA Corporation, Bedford, MA, October 1980.

19. N.F. Suprenant, et al., Emissions Assessment of Conventional Stationary Combustion Systems, Volume V: Industrial Combustion Sources, EPA Contract No. 68-02-2197, GCA Corporation, Bedford, MA, October 1980.

20. K.J. Lim, et al., Technology Assessment Report for Industrial Boiler Applications: NOx Combustion Modification, EPA-600/7-79-178f, U.S. Environmental Protection Agency, Washington, DC, December 1979.

21. Emission Test Reports, Docket No. OAQPS-78-1, Category II-I-257 through 265, Office Of Air Quality Planning And Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, 1972 through 1974.

22. Primary Sulfate Emissions from Coal and Oil Combustion, EPA Contract No. 68-02-3138, TRW, Inc., Redondo Beach, CA, February 1980.

23. C. Leavitt, et al., Environmental Assessment of an Oil Fired Controlled Utility Boiler, EPA-600/7-80-087, U.S. Environmental Protection Agency, Washington, DC, April 1980.

24. W.A. Carter and R.J. Tidona, Thirty-day Field Tests of Industrial Boilers: Site 2 - Residual-oil-fired Boiler, EPA-600/7-80-085b, U.S. Environmental Protection Agency, Washington, DC, April 1980.

25. D.W. Pershing, et al., Influence of Design Variables on the Production of Thermal and Fuel NO from Residual Oil and Coal Combustion, Air: Control of NOx and SOx Emissions, New York, American Institute of Chemical Engineers, 1975.

26. Fossil Fuel Fired Industrial Boilers - Background Information: Volume 1, EPA-450/3-82-006a, U.S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.

27. U.S. Environmental Protection Agency, "National Primary and Secondary Ambient Air Quality Standards," Code of Federal Regulations, Title 40, Part 50, U.S. Government Printing Office, Washington DC, 1991.

28. R. Clayton, et al., N_2O Field Study, EPA-600/2-89-006, U.S. Environmental Protection Agency, Research Triangle Park, NC, February 1989.

29. Evaluation of Fuel-Based Additives for N_2O and Air Toxic Control in Fluidized Bed Combustion Boilers, EPRI Contract No. RP3197-02, Acurex Report No. FR-91-101-/ESD, (Draft Report) Acurex Environmental, Mountain View, CA, June 17, 1991.

30. Particulate Polycyclic Organic Matter, Nation Academy of Sciences, Washington, DC, 1972.

31. Vapor Phase Organic Pollutants -- Volatile Hydrocarbons and Oxidation Products, National Academy of Sciences, Washington, DC, 1976.

32. H. Knierien, A Theoretical Study of PCB Emissions from Stationary Sources, EPA-600/7-76-028, U.S. Environmental Protection Agency, Research Triangle Park, NC, September 1976.

33. Estimating Air Toxics Emissions From Coal and Oil Combustion Sources, EPA-450/2-89-001, U.S. Environmental Protection Agency, Research Triangle Park, NC, April 1989.

34. R.P. Hagebrauck, D.J. Von Lehmden, and J.E. Meeker, "Emissions of Polynuclear Hydrocarbons and Other Pollutants from Heat-Generation and Incineration Process," J. Air Pollution Control Assoc, 14:267-278, 1964.

35. M.B. Rogozen, et al., Formaldehyde: A Survey of Airborne Concentration and Sources, California Air Resources Board, ARB report no. ARB/R-84-231, 1984.

36. Clean Air Act Amendments of 1990, Conference Report To Accompany S. 1603, Report 101-952, U.S. Government Printing Office, Washington, DC, October 26, 1990.

37. K.J. Lim, et al., Industrial Boiler Combustion Modification NOx Controls - Volume I Environmental Assessment, EPA-600/7-81-126a, U.S. Environmental Protection Agency, July 1981.

38. D.H. Klein, et al., "Pathways of Thirty-Seven Trace Elements Through Coal-Fired Power Plants," Environ. Sci. Technol., 9:973-979, 1975.

39. D.G. Coles, et al., "Chemical Studies of Stack Fly Ash From a Coal-Fired Power Plant," Environ. Sci. Technol., 13:455-459, 1979.

40. S. Baig, et al., Conventional Combustion Environmental Assessment, EPA Contract No. 68-02-3138, U.S. Environmental Protection Agency, Research Triangle Park, NC, 1981.

41. Code of Federal Regulations, 40, Parts 53 to 60 , July 1, 1991.

42. Environmental Assessment of Coal and Oil Firing in a Controlled Industrial Boiler, Volume I, PB 289942, U.S. Environmental Protection Agency, August 1978.

43. Environmental Assessment of Coal and Oil Firing in a Controlled Industrial Boiler, Volume II, EPA-600/7-78-164b, U.S. Environmental Protection Agency, August 1978.

44. Environmental Assessment of Coal and Oil Firing in a Controlled Industrial Boiler, Volume III, EPA-600/7-78-164c, U.S. Environmental Protection Agency, August 1978.

45 Emission Reduction on Two Industrial Boilers with Major Combustion Modifications, EPA-600/7-78-099a, U.S. Environmental Protection Agency, August 1978.

46. Emission Reduction on Two Industrial Boilers with Major Combustion Modifications, Data Supplement, EPA-600/7-78-099b, U.S. Environmental Protection Agency, August 1978.

47. Industrial Boilers Emission Test Report, Boston Edison Company, Everett, Massachusetts, EMB Report 81-IBR-15, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, October 1981.

48. Residential Oil Furnace System Optimization, phase II, EPA-600/2-77-028, U.S. Environmental Protection Agency, January 1977.

49. Characterization of Particulate Emissions from Refinery Process Heaters and Boilers, API Publication No. 4365, June 1983. U.S. Environmental Protection Agency, January 1977.

50. James Ekmann, et al., Comparison of Shale Oil and Residual Fuel Combustion in Symposium Papers New Fuels and Advances in Combustion Technologies Sponsored by Institute of Gas Technology, March 1979.

51. Overview of the Regulatory Baseline, Technical Basis, and Alternative Control Levels for SO2 Emission Standards for Small Steam Generating Units, EPA-450/3-89-012, U.S. Environmental Protection Agency, May 1989.

52. Overview of the Regulatory Baseline, Technical Basis, and Alternative Control Levels for NOx Emission Standards for Small Steam Generating Units, EPA-450/3-89-013, U.S. Environmental Protection Agency, May 1989.

53. Overview of the Regulatory Baseline, Technical Basis, and Alternative Control Levels for PM Emission Standards for Small Steam Generating Units, EPA-450/3-89-014, U.S. Environmental Protection Agency, May 1989.

54. Flue Gas Desulfurization: Installations and Operations, PB 257721, National Technical Information Service, Springfield, VA, September 1974.

55. Proceedings: Flue Gas Desulfurization Symposium - 1973, EPA-650/2-73-038, U.S. Environmental Protection Agency, Washington, DC, December 1973.

56. G.R. Offen, et al., Control of Particulate Matter from Oil Burners and Boilers, EPA-450/3-76-005, U.S. Environmental Protection Agency, Research Triangle Park, NC, April 1976.

57. J.H. Pohl and A.F. Sarofim, Devolatilization and Oxidation of Coal Nitrogen (presented at the 16th International Symposium on Combustion), August 1976.

58. D.W. Pershing and J. Wendt, Relative Contribution of Volatile and Char Nitrogen to NOx Emissions From Pulverized Coal Flames, Industrial Engineering Chemical Proceedings, Design and Development, 1979.

59. D.W. Pershing, Nitrogen Oxide Formation in Pulverized Coal Flames, Ph.D. Dissertation, University of Arizona, 1976.

60. P.B. Nutcher, High Technology Low NOx Burner Systems for Fired Heaters and Steam Generators, Process Combustion Corp., Pittsburgh, PA, Presented at the Pacific Coast Oil Show and Conference, Los Angeles, CA, November 1982.

61. M.N. Mansour, et al., Integrated NOx Reduction Plan to Meet Staged SCAQMD Requirements for Steam Electric Power Plants, Proceedings of the 53rd American Power Conference, 1991.

62. D.W. South, et al., Technologies and Other Measures For Controlling Emissions: Performance, Costs, and Applicability, Acidic Deposition: State of Science and Technology, Volume IV, Report 25, National Acid Precipitation Assessment Program, U.S. Government Printing Office, Washington, DC, December 1990.

63. EPA Industrial Boiler FGD Survey: First Quarter 1979, EPA-600/7-79-067b, U.S. Environmental Protection Agency, April 1979.

1.4 NATURAL GAS COMBUSTION

1.4.1 General[1-2]

Natural gas is one of the major fuels used throughout the country. It is used mainly for industrial process steam and heat production; for residential and commercial space heating; and for electric power generation. Natural gas consists of a high percentage of methane (generally above 80 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). Gas processing plants are required for the recovery of liquefiable constituents and removal of hydrogen sulfide before the gas is used (see Natural Gas Processing, Section 9.2). The average gross heating value of natural gas is approximately 8900 kilocalories per standard cubic meter (1000 British thermal units per standard cubic foot), usually varying from 8000 to 9800 kcal/scm (900 to 1100 Btu/scf).

1.4.2 Emissions and Controls[3-5]

Even though natural gas is considered to be a relatively clean-burning fuel, some emissions can result from combustion. For example, improper operating conditions, including poor air/fuel mixing, insufficient air, etc., may cause large amounts of smoke, carbon monoxide (CO), and organic compound emissions. Moreover, because a sulfur-containing mercaptan is added to natural gas to permit leak detection, small amounts of sulfur oxides will be produced in the combustion process.

Nitrogen oxides (NO_x) are the major pollutants of concern when burning natural gas. Nitrogen oxide emissions depend primarily on the peak temperature within the combustion chamber as well as the furnace-zone oxygen concentration, nitrogen concentration, and time of exposure at peak temperatures. Emission levels vary considerably with the type and size of combustor and with operating conditions (particularly combustion air temperature, load, and excess air level in boilers).

Currently, the two most prevalent NO_x control techniques being applied to natural gas-fired boilers (which result in characteristic changes in emission rates) are low NO_x burners and flue gas recirculation. Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses NO_x formation. The three most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners, staged fuel burners, and radiant fiber burners. Nitrogen oxide emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners. Other combustion staging techniques which have been applied to natural gas-fired boilers include low excess air, reduced air preheat, and staged combustion (e.g., burners-out-of-service and overfire air). The degree of staging is a key operating parameter influencing NO_x emission rates for these systems.

In a flue gas recirculation (FGR) system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the gas is mixed with combustion air prior to being fed to the burner. The FGR system reduces NO_x emissions by two mechanisms. The recycled flue gas in made up of combustion products which act as inerts during combustion of the fuel/air mixture. This additional mass is heated in the combustion zone, thereby lowering the peak flame temperature and reducing the amount of NO_x formed. To a lesser extent, FGR also reduces NO_x formation by

lowering the oxygen concentration in the primary flame zone. The amount of flue gas recirculated is a key operating parameter influencing NO_x emission rates for these systems. Flue gas recirculation is normally used in combination with low NO_x burners. When used in combination, these techniques are capable of reducing uncontrolled NO_x emissions by 60 to 90 percent.

Two post-combustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions by further amounts are selective noncatalytic reduction and selective catalytic reduction. These systems inject ammonia (or urea) into combustion flue gases to reduce inlet NO_x emission rates by 40 to 70 percent.

Although not measured, all particulate matter (PM) from natural gas combustion has been estimated to be less than 1 micrometer in size. Particulate matter is composed of filterable and condensible fractions, based on the EPA sampling method. Filterable and condensible emission rates are of the same order of magnitude for boilers; for residential furnaces, most of the PM is in the form of condensible material.

The rates of CO and trace organic emissions from boilers and furnaces depend on the efficiency of natural gas combustion. These emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. In some cases, the addition of NO_x control systems such as FGR and low NO_x burners reduces combustion efficiency (due to lower combustion temperatures), resulting in higher CO and organic emissions relative to uncontrolled boilers.

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1 through 1.4-3. For the purposes of developing emission factors, natural gas combustors have been organized into four general categories: utility/large industrial boilers, small industrial boilers, commercial boilers, and residential furnaces. Boilers and furnaces within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas. The primary factor used to demarcate the individual combustor categories is heat input.

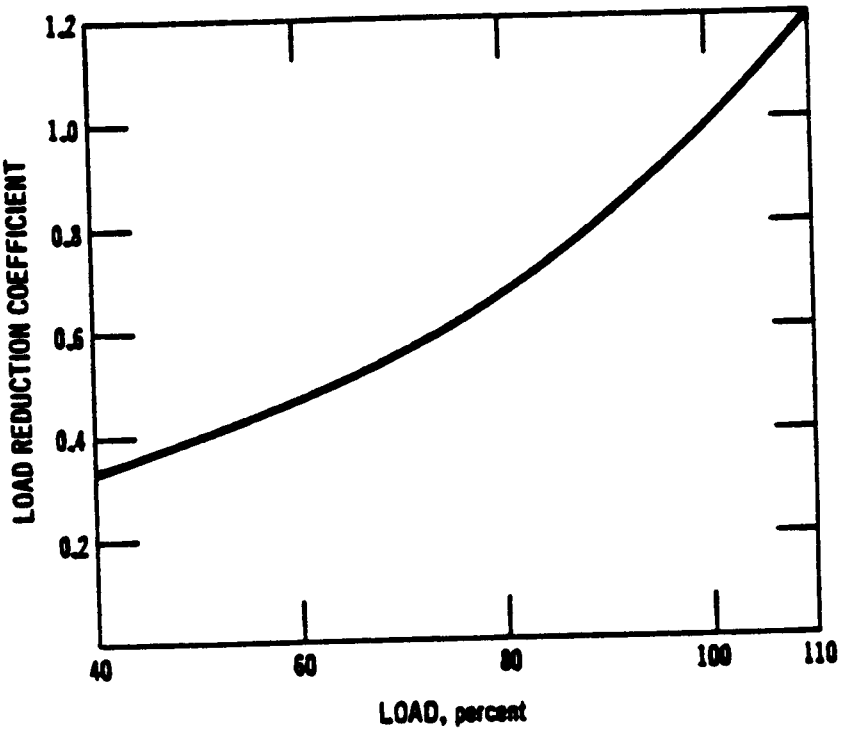


Figure 1.4-1. Load reduction coefficient as a function of boiler load. (Used to determine NO_x reductions at reduced loads in large boilers.)

Table 1.4-1. EMISSION FACTORS FOR PARTICULATE MATTER (PM) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr heat input) [SCC][b]	Filterable PM[c]			Condensible PM[d]		
	kg/10^6 m^3	lb/10^6 ft^3	Rating	kg/10^6 m^3	lb/10^6 ft^3	Rating
Utility/large industrial boilers (>100) [10106001, 10100604]	16-80	1-5	B	ND[e]	ND	
Small industrial boilers (10 - 100) [10200602]	99	6.2	B	120	7.5	D
Commercial boilers (0.3 -<10) [10300603]	72	4.5	C	120	7.5	C
Residential furnaces (<0.3) [no SCC]	2.8	0.18	C	180	11	D

[a]References 9-14. All factors represent uncontrolled emissions. Units are kg of pollutant/10^6 cubic meters and lbs. of pollutant/10^6 cubic feet. Based on an average natural gas higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

[b]SCC = Source Classification Code.

[c]Filterable PM is that particulate matter collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

[d]Condensible PM is that particulate matter collected in the impinger portion of an EPA Method 5 (or equivalent) sampling train. Total PM is the sum of the filterable PM and condensible PM. All PM emissions can be assumed to be less than 10 microns in aerodynamic equivalent diameter (PM-10).

[e]ND = No data.

Table 1.4-2. EMISSION FACTORS FOR SULFUR DIOXIDE (SO_2), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr heat input) [SCC][b]	SO_2[c]			NO_x[d]			CO[e]		
	kg/10^6m^3	lb/10^6ft^3	Rating	kg/10^6m^3	lb/10^6ft^3	Rating	kg/10^6m^3	lb/10^6ft^3	Rating
Utility/Large Industrial Boilers (>100) [10100601, 10100604]									
Uncontrolled	9.6	0.6	A	8800	550[f]	A	640	40	A
Controlled - Low NO_x burners	9.6	0.6	A	1300	81[f]	D	ND[g]	ND	
Controlled - Flue gas recirculation	9.6	0.6	A	850	53[f]	D	ND	ND	
Small Industrial Boilers (10-100) [10200602]									
Uncontrolled	9.6	0.6	A	2240	140	A	560	35	A
Controlled - Low NO_x burners	9.6	0.6	A	1300	81[f]	D	980	61	D
Controlled - Flue gas recirculation	9.6	0.6	A	480	30	C	590	37	C
Commercial Boilers (0.3-<10) [10300603]									
Uncontrolled	9.6	0.6	A	1600	100	B	330	21	C
Controlled - Low NO_x burners	9.6	0.6	A	270	17	C	425	27	C
Controlled - *Flue gas recirculation*	9.6	0.6	A	580	36	D	ND	ND	
Residential Furnaces (<0.3) [no SCC]									
Uncontrolled	9.6	0.6	A	1500	94	B	640	40	B

[a]Units are kg of pollutant/10^6 cubic meters and lbs. of pollutant/10^6 cubic feet. Based on an average natural gas higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

[b]SCC = Source Classification Code.

[d]Reference 7. Based on average sulfur content of natural gas, 4600 g/10^6 Nm^3 (2000 gr/10^6 scf).

[e]References 10, 15-19. Expressed as NO_2. For tangentially fired units, use 4400 kg/10^6 m^3 (275 lb/10^6 ft^3). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1. Note that NO_x emissions from controlled boilers will be reduced at low load conditions.

[f]References 9-10, 16-18, 20-21.

[g]Emission factors apply to packaged boilers only.

[h]ND = No data.

Table 1.4-3. EMISSION FACTORS FOR CARBON DIOXIDE (CO_2), AND TOTAL ORGANIC COMPOUNDS (TOC) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (Size, 10^6 Btu/hr heat input) [SCC][b]	CO_2[c]			TOC[d]		
	$kg/10^6m^3$	$lb/10^6ft^3$	Rating	$kg/10^6m^3$	$lb/10^6ft^3$	Rating
Utility/large industrial boilers (>100) [10100601, 10100604]	ND[e]	ND		28[f]	1.7[f]	C
Small industrial boilers (10-100) [10200602]	1.9E06	1.2E05	D	92[g]	5.8[g]	C
Commercial boilers (0.3-<10) [10300603]	1.9E06	1.2E05	C	92[h]	5.8[h]	C
Residential furnaces [no SCC]	2.0E06	1.3E05	D	180[h]	11[h]	D

[a]All factors represent uncontrolled emissions. Units are kg of pollutant/10^6 cubic meters and lbs. of pollutant/10^6 cubic feet. Based on an average natural gas higher heating value of 8270 kcal/m^3 (1000 Btu/scf). The emission factors in this table may be converted to other natural gas heating values bay multiplying the given factor by the ratio of the specified heating value to this average heating value.
[b]SCC = Source Classification Code.
[c]References 10, 22-23.
[d]References 9-10, 18.
[e]ND = No data.
[f]Reference 8: methane comprises 17 percent of organic compounds.
[g]Reference 8: methane comprises 52 percent of organic compounds.
[h]Reference 8: methane comprises 34 percent of organic compounds.

References for Section 1.4

1. *Exhaust Gases From Combustion and Industrial Processes*, EPA Contract No. EHSD 71-36, Engineering Science, Inc., Washington, DC, October 1971.

2. *Chemical Engineers' Handbook, Fourth Edition*, J. H. Perry, Editor, McGraw-Hill Book Company, New York, NY, 1963.

3. *Background Information Document For Industrial Boilers*, EPA-450/3-82-006a, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.

4. *Background Information Document For Small Steam Generating Units*, EPA-450/3-87-000, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1987.

5. *Fine Particulate Emissions From Stationary and Miscellaneous Sources in the South Coast Air Basin*, California Air Resources Board Contract No. A6-191-30, KVB, Inc., Tustin, CA, February 1979.

6. *Emission Factor Documentation for AP-42 Section 1.4 - Natural Gas Combustion (Draft)*, Technical Support Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1993.

7. *Systematic Field Study of NO_x Emission Control Methods For Utility Boilers*, APTD-1163, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1971.

8. *Compilation of Air Pollutant Emission Factors*, Fourth Edition, AP-42, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1985.

9. J. L. Muhlbaier, "Particulate and Gaseous Emissions From Natural Gas Furnaces and Water Heaters", *Journal of the Air Pollution Control Association*, December 1981.

10. *Field Investigation of Emissions From Combustion Equipment for Space Heating*, EPA-R2-73-084a, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1973.

11. N. F. Suprenant, *et al.*, *Emissions Assessment of Conventional Stationary Combustion Systems, Volume I: Gas and Oil Fired Residential Heating Sources*, EPA-600/7-79-029b, U. S. Environmental Protection Agency, Washington, DC, May 1979.

12. C. C. Shih, *et al.*, *Emissions Assessment of Conventional Stationary Combustion Systems, Volume III: External Combustion Sources for Electricity Generation*, EPA Contract No. 68-02-2197, TRW, Inc., Redondo Beach, CA, November 1980.

13. N. F. Suprenant, *et al.*, *Emissions Assessment of Conventional Stationary Combustion Systems, Volume IV: Commercial/Institutional Combustion Sources*, EPA Contract No. 68-02-2197, GCA Corporation, Bedford, MA, October 1980.

References for Section 1.4 (Continued)

14. N. F. Suprenant, *et al., Emissions Assessment of Conventional Stationary Combustion Systems, Volume V: Industrial Combustion Sources*, EPA Contract No. 68-02-2197, GCA Corporation, Bedford, MA, October 1980.

15. *Emissions Test on 200 HP Boiler at Kaiser Hospital in Woodland Hills*, Energy Systems Associates, Tustin, CA, June 1986.

16. *Results From Performance Tests: California Milk Producers Boiler No. 5*, Energy Systems Associates, Tustin, CA, November 1984.

17. *Source Test For Measurement of Nitrogen Oxides and Carbon Monoxide Emissions From Boiler Exhaust at GAF Building Materials*, Pacific Environmental Services, Inc., Baldwin Park, CA, May 1991.

18. J. P. Kesselring and W. V. Krill, "A Low-NO_x Burner For Gas-Fired Firetube Boilers", *Proceedings: 1985 Symposium on Stationary Combustion NO_x Control, Volume 2*, EPRI CS-4360, Electric Power Research Institute, Palo Alto, CA, January 1986.

19. *NO_x Emission Control Technology Update*, EPA Contract No. 68-01-6558, Radian Corporation, Research Triangle Park, NC, January 1984.

20. *Background Information Document For Small Steam Generating Units*, EPA-450/3-87-000, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1987.

21. *Evaluation of the Pollutant Emissions From Gas-Fired Forced Air Furnaces: Research Report No. 1503*, American Gas Association Laboratories, Cleveland, OH, May 1975.

22. *Thirty-day Field Tests of Industrial Boilers: Site 5 - Gas-fired Low-NO_x Burner*, EPA-600/7-81-095a, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1981.

23. Private communication from Kim Black (Industrial Combustion) to Ralph Harris (MRI), Independent Third Party Source Tests, February 7, 1992.

1.5 LIQUEFIED PETROLEUM GAS COMBUSTION

1.5.1 General[1]

Liquefied petroleum gas (LPG or LP-gas) consists of propane, propylene, butane, and butylenes; the product used for domestic heating is substantially propane. This gas, obtained mostly from gas wells (but also to a lesser extent as a refinery by-product) is stored as a liquid under moderate pressures. There are three grades of LPG available as heating fuels: commercial-grade propane, engine fuel-grade propane (also known as HD-5 propane), and commercial-grade butane. In addition, there are high purity grades of LPG available for laboratory work and for use as aerosol propellants. Specifications for the various LPG grades are available from the American Society for Testing and Materials and the Gas Processors Association. A typical heating value for commercial-grade propane and HD-5 propane is 6,090 kcal/liter (91,500 Btu/gallon), after vaporization; for commercial-grade butane, the value is 6,790 kcal/liter (102,000 Btu/gallon).

The largest market for LPG is the domestic/commercial market, followed by the chemical industry (where it is used as a petrochemical feedstock) and agriculture. Propane is also used as an engine fuel as an alternative to gasoline and as a stand-by fuel for facilities that have interruptible natural gas service contracts.

1.5.2 Emissions and Controls[1-4]

Liquefied petroleum gas is considered a "clean" fuel because it does not produce visible emissions. However, gaseous pollutants such as carbon monoxide (CO), organic compounds, and nitrogen oxides (NO_x) do occur. The most significant factors affecting these emissions are burner design, burner adjustment, and flue gas venting. Improper design, blocking and clogging of the flue vent, and insufficient combustion air result in improper combustion and the emissions of aldehydes, CO, hydrocarbons, and other organics. Nitrogen oxide emissions are a function of a number of variables, including temperature, excess air, fuel/air mixing, and residence time in the combustion zone. The amount of sulfur dioxide (SO_2) emitted is directly proportional to the amount of sulfur in the fuel. Emission factors for LPG combustion are presented in Tables 1.5-1 and 1.5-2.

Nitrogen oxides are the only pollutant for which emission controls have been developed. Propane and butane are being used in Southern California as backup fuel to natural gas, replacing distillate oil in this role pursuant to the phaseout of fuel oil in that region. Emission controls for NO_x have been developed for firetube and watertube boilers firing propane or butane. Vendors are now warranting retrofit systems to levels as low as 30 to 40 ppm (based on 3 percent oxygen). These low-NO_x systems use a combination of low NO_x burners and flue gas recirculation. Some burner vendors use water or steam injection into the flame zone for NO_x reduction. This is a trimming technique which may be necessary during backup fuel periods because LPG typically has a higher NO_x-forming potential than natural gas; conventional natural gas emission control systems may not be sufficient to reduce LPG emissions to mandated levels. Also, LPG burners are more prone to sooting under the modified combustion conditions required for low NO_x emissions. The extent of allowable combustion modifications for LPG may be more limited than for natural gas.

One NO_x control system that has been demonstrated on small commercial boilers is flue gas recirculation (FGR). Nitrogen oxide emissions from propane combustion can be reduced by as much

as 50 percent by recirculating 16 percent of the flue gas. Nitrogen oxide emission reductions of over 60 percent have been achieved with FGR and low NO_x burners used in combination.

TABLE 1.5-1. (ENGLISH UNITS) EMISSION FACTORS FOR LPG COMBUSTION[a]
(Source Classification Codes)

EMISSION FACTOR RATING: E

Pollutant	Butane Emission Factor lb/1000 gal		Propane Emission Factor lb/1000 gal	
	Industrial Boilers[b] (10201001)	Commercial Boilers[c] (10301001)	Industrial Boilers[b] (10201002)	Commercial Boilers[c] (10301002)
Filterable particulate matter[d]	0.6	0.5	0.6	0.4
Sulfur oxides[e]	0.09S	0.09S	0.10S	0.10S
Nitrogen oxides[f]	21	15	19	14
Carbon dioxide	14,700	14,700	12,500	12,500
Carbon monoxide	3.6	2.1	3.2	1.9
Total organic compounds	0.6	0.6	0.5	0.5

[a]Assumes emissions (except SO_x and NO_x) are the same, on a heat input basis, as for natural gas combustion. The NO_x emission factors have been multiplied by a correction factor of 1.5 which is the approximate ratio of propane/butane NO_x emissions to natural gas NO_x emissions.
[b]Heat input capacities generally between 10 and 100 million Btu/hour.
[c]Heat input capacities generally between 0.3 and 10 million Btu/hour.
[d]Filterable particulate matter (PM) is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
[e]Expressed as SO_2. S equals the sulfur content expressed on gr/100 ft^3 gas vapor. For example, if the butane sulfur content is 0.18 gr/100 ft^3 emission factor would be (0.09 x 0.18=) 0.016 lb of SO_2/1000 gal butane burned.
[f]Expressed as NO_2.

TABLE 1.5-2. (METRIC UNITS) EMISSION FACTORS FOR LPG COMBUSTION[a]
(Source Classification Codes)

EMISSION FACTOR RATING: E

Pollutant	Butane Emission Factor kg/1000 liters		Propane Emission Factor kg/1000 liters	
	Industrial Boilers[b] (10201001)	Commercial Boilers[c] (10301001)	Industrial Boilers[b] (10201002)	Commercial Boilers[c] (10301002)
Filterable particulate matter[d]	0.07	0.06	0.07	0.05
Sulfur oxides[e]	0.011S	0.011S	0.012S	0.012S
Nitrogen oxides[f]	2.5	1.8	2.3	1.7
Carbon dioxide	1,760	1,760	1,500	1,500
Carbon monoxide	0.4	0.3	0.4	0.2
Total organic compounds	0.07	0.07	0.06	0.06

[a]Assumes emissions (except SO_x and NO_x) are the same, on a heat input basis, as for natural gas combustion. The NO_x emission factors have been multiplied by a correction factor of 1.5 which is the approximate ratio of propane/butane NO_x emissions to natural gas NO_x emissions.
[b]Heat input capacities generally between 3 and 29 MW.
[c]Heat input capacities generally between 0.1 and 3 MW.
[d]Filterable particulate matter (PM) is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
[e]Expressed as SO_2. S equals the sulfur content expressed on gr/100 ft^3 gas vapor. For example, if the butane sulfur content is 0.18 gr/100 ft^3 emission factor would be (0.011 x 0.18) = 0.0020 kg of SO_2/1000 liters butane burned.
[f]Expressed as NO_2.

References for Section 1.5

1. Letter dated August 19, 1992. From W. Butterbaugh of the National Propane Gas Association, Lisle, Illinois, to J. McSorley of the U.S. Environmental Protection Agency, Research Triangle Park, NC.

2. Air Pollutant Emission Factors, Final Report, Contract No. CPA-22-69-119, Resources Research, Inc., Reston, VA, Durham, NC, April 1970.

3. Nitrous Oxide Reduction with the Weishaupt Flue Gas Recirculation System, Weishaupt Research and Development Institute, January. 1987.

4. Phone communication memorandum dated May 14, 1992. Conversation between B. Lusher of Acurex Environmental and D. Childress of Suburban/Petrolane, Durham, NC.

1.6 WOOD WASTE COMBUSTION IN BOILERS

1.6.1 General[1-5]

The burning of wood waste in boilers is mostly confined to those industries where it is available as a byproduct. It is burned both to obtain heat energy and to alleviate possible solid waste disposal problems. In boilers, wood waste is normally burned in the form of hogged wood, sawdust, shavings, chips, sanderdust, or wood trim. Heating values for this waste range from about 2,200 to 2,700 kcal/kg (4,000 to 5,000 Btu/lb) of fuel on a wet, as-fired basis. The moisture content of as-fired wood is typically near 50, weight percent but may vary from 5 to 75 weight percent depending on the waste type and storage operations.

Generally, bark is the major type of waste burned in pulp mills; either a mixture of wood and bark waste or wood waste alone is burned most frequently in the lumber, furniture, and plywood industries. As of 1980, there were approximately 1,600 wood-fired boilers operating in the U.S., with a total capacity of over 30 GW (1.0×10^{11} Btu/hr).

1.6.2 Firing Practices[5-7]

Various boiler firing configurations are used for burning wood waste. One common type of boiler used in smaller operations is the Dutch oven. This unit is widely used because it can burn fuels with very high moisture content. Fuel is fed into the oven through an opening in the top of a refractory-lined furnace. The fuel accumulates in a cone-shaped pile on a flat or sloping grate. Combustion is accomplished in two stages: (1) drying and gasification, and (2) combustion of gaseous products. The first stage takes place in the primary furnace, which is separated from the secondary furnace chamber by a bridge wall. Combustion is completed in the secondary chamber before gases enter the boiler section. The large mass of refractory helps to stabilize combustion rates but also causes a slow response to fluctuating steam demand.

In another boiler type, the fuel cell oven, fuel is dropped onto suspended fixed grates and is fired in a pile. Unlike the Dutch oven, the refractory-lined fuel cell also uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Because of their overall design and operating similarities, however, fuel cell and Dutch oven boilers have comparable emission characteristics.

The most common firing method employed for wood-fired boilers larger than 45,000 kg/hr (100,000 lb/hr) steam generation rate is the spreader stoker. With this boiler, wood enters the furnace through a fuel chute and is spread either pneumatically or mechanically across the furnace, where small pieces of the fuel burn while in suspension. Simultaneously, larger pieces of fuel are spread in a thin, even bed on a stationary or moving grate. The burning is accomplished in three stages in a single chamber: (1) moisture evaporation; (2) distillation and burning of volatile matter; and (3) burning of fixed carbon. This type of operation has a fast response to load changes, has improved combustion control, and can be operated with multiple fuels. Natural gas or oil is often fired in spreader stoker boilers as auxiliary fuel. This is done to maintain constant steam when the wood waste supply fluctuates and/or to provide more steam than can be generated from the waste supply

alone. Although spreader stokers are the most common stokers among larger wood-fired boilers, overfeed and underfeed stokers are also utilized for smaller units.

Another boiler type sometimes used for wood combustion is the suspension-firing boiler. This boiler differs from a spreader stoker in that small-sized fuel (normally less than 2 mm) is blown into the boiler and combusted by supporting it in air rather than on fixed grates. Rapid changes in combustion rate and, therefore, steam generation rate are possible because the finely divided fuel particles burn very quickly.

A recent development in wood firing is the fluidized bed combustion (FBC) boiler. A fluidized bed consists of inert particles through which air is blown so that the bed behaves as a fluid. Wood waste enters in the space above the bed and burns both in suspension and in the bed. Because of the large thermal mass represented by the hot inert bed particles, fluidized beds can handle fuels with moisture contents up to near 70 percent (total basis). Fluidized beds can also handle dirty fuels (up to 30 percent inert material). Wood fuel is pyrolyzed faster in a fluidized bed than on a grate due to its immediate contact with hot bed material. As a result, combustion is rapid and results in nearly complete combustion of the organic matter, thereby minimizing emission of unburned organic compounds.

1.6.3 Emissions And Controls[6-11]

The major emission of concern from wood boilers is particulate matter (PM), although other pollutants, particularly carbon monoxide (CO) and organic compounds, may be emitted in significant quantities under poor operating conditions. These emissions depend on a number of variables, including (1) the composition of the waste fuel burned, (2) the degree of flyash reinjection employed and (3) furnace design and operating conditions.

The composition of wood waste depends largely on the industry from which it originates. Pulping operations, for example, produce great quantities of bark that may contain more than 70 weight percent moisture, sand, and other non-combustibles. As a result, bark boilers in pulp mills may emit considerable amounts of particulate matter to the atmosphere unless they are well controlled. On the other hand, some operations, such as furniture manufacturing, generate a clean, dry wood waste (e.g., 2 to 20 weight percent moisture) which produces relatively low particulate emission levels when properly burned. Still other operations, such as sawmills, burn a varying mixture of bark and wood waste that results in PM emissions somewhere between these two extremes.

Furnace design and operating conditions are particularly important when firing wood waste. For example, because of the high moisture content that may be present in wood waste, a larger than usual area of refractory surface is often necessary to dry the fuel before combustion. In addition, sufficient secondary air must be supplied over the fuel bed to burn the volatiles that account for most of the combustible material in the waste. When proper drying conditions do not exist, or when secondary combustion is incomplete, the combustion temperature is lowered, and increased PM, CO, and organic compound emissions may result. Short term emissions can fluctuate with significant variations in fuel moisture content.

Flyash reinjection, which is commonly used with larger boilers to improve fuel efficiency, has a considerable effect on PM emissions. Because a fraction of the collected flyash is reinjected into the boiler, the dust loading from the furnace and, consequently, from the collection device increase

significantly per unit of wood waste burned. More recent boiler installations typically separate the collected particulate into large and small fractions in sand classifiers. The larger particles, which are mostly carbon, are reinjected into the furnace. The smaller particles, mostly inorganic ash and sand, are sent to ash disposal.

Currently, the four most common control devices used to reduce PM emissions from wood-fired boilers are mechanical collectors, wet scrubbers, electrostatic precipitators (ESPs), and fabric filters. The use of multitube cyclone (or multiclone) mechanical collectors provides particulate control for many hogged boilers. Often, two multiclones are used in series, allowing the first collector to remove the bulk of the dust and the second to remove smaller particles. The efficiency of this arrangement is from 65 to 95 percent. The most widely used wet scrubbers for wood-fired boilers are venturi scrubbers. With gas-side pressure drops exceeding 4 kPa (15 inches of water), particulate collection efficiencies of 90 percent or greater have been reported for venturi scrubbers operating on wood-fired boilers.

Fabric filters (i.e., baghouses) and ESPs are employed when collection efficiencies above 95 percent are required. When applied to wood-fired boilers, ESPs are often used downstream of mechanical collector precleaners which remove larger-sized particles. Collection efficiencies of 93 to 99.8 percent for PM have been observed for ESPs operating on wood-fired boilers.

A variation of the ESP is the electrostatic gravel bed filter. In this device, PM in flue gases is removed by impaction with gravel media inside a packed bed; collection is augmented by an electrically charged grid within the bed. Particulate collection efficiencies are typically near 95 percent.

Fabric filters have had limited applications to wood-fired boilers. The principal drawback to fabric filtration, as perceived by potential users, is a fire danger arising from the collection of combustible carbonaceous fly ash. Steps can be taken to reduce this hazard, including the installation of a mechanical collector upstream of the fabric filter to remove large burning particles of fly ash (i.e., "sparklers"). Despite complications, fabric filters are generally preferred for boilers firing salt-laden wood. This fuel produces fine particulates with a high salt content. Fabric filters are capable of high fine particle collection efficiencies; in addition, the salt content of the particles has a quenching effect, thereby reducing fire hazards. In two tests of fabric filters operating on salt-laden wood-fired boilers, particulate collection efficiencies were above 98 percent.

Emissions of nitrogen oxides (NO_x) from wood-fired boilers are lower than those from coal-fired boilers due to the lower nitrogen content of wood and the lower combustion temperatures which characterize wood-fired boilers. For stoker and FBC boilers, overfire air ports may be used to lower NO_x emissions by staging the combustion process. In those areas of the U.S. where NO_x emissions must be reduced to their lowest levels, the application of selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) to waste wood-fired boilers has either been accomplished (SNCR) or is being contemplated (SCR). Both systems are post-combustion NO_x reduction techniques in which ammonia (or urea) is injected into the flue gas to selectively reduce NO_x to nitrogen and water. In one application of SNCR to an industrial wood-fired boiler, NO_x reduction efficiencies varied between 35 and 75 percent as the ammonia:NO_x ratio increased from 0.4 to 3.2.

Emission factors and emission factor ratings for wood waste boilers are summarized in Tables 1.6-1 through 1.6-7. Emission factors are for uncontrolled combustors, unless otherwise indicated.

Cumulative particle size distribution data and associated emission factors are presented in Tables 1.6-8 and 1.6-9. Uncontrolled and controlled size-specific emission factors are plotted in Figures 1.6-1 and 1.6-2. All emission factors presented are based on the feed rate of wet, as-fired wood with average properties of 50 weight percent moisture and 2,500 kcal/kg (4,500 Btu/lb) higher heating values.

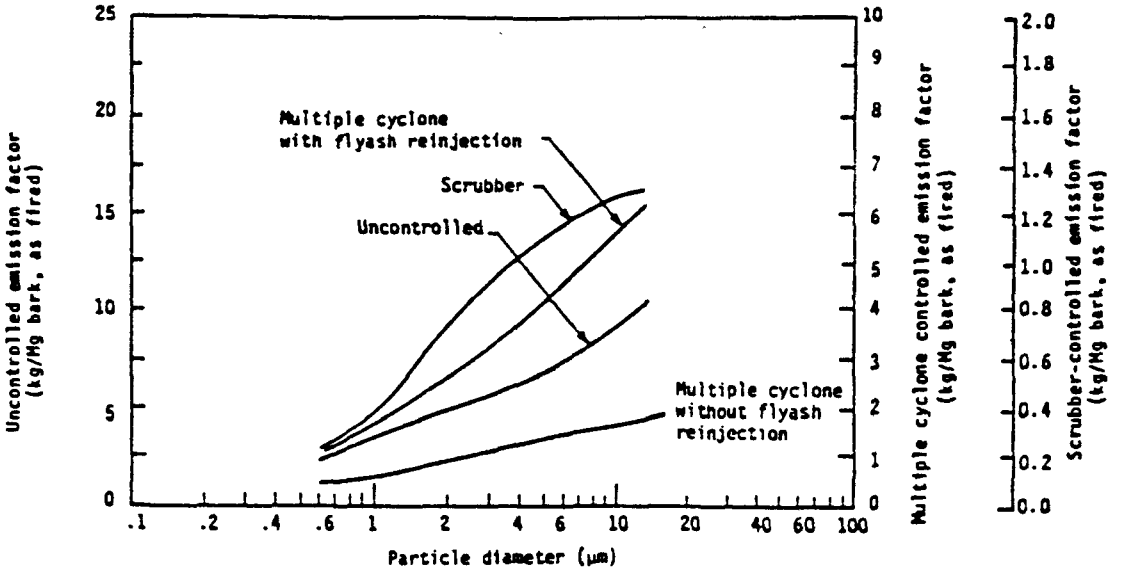


Figure 1.6-1. Cumulative size specific emission factors for bark fired boilers.

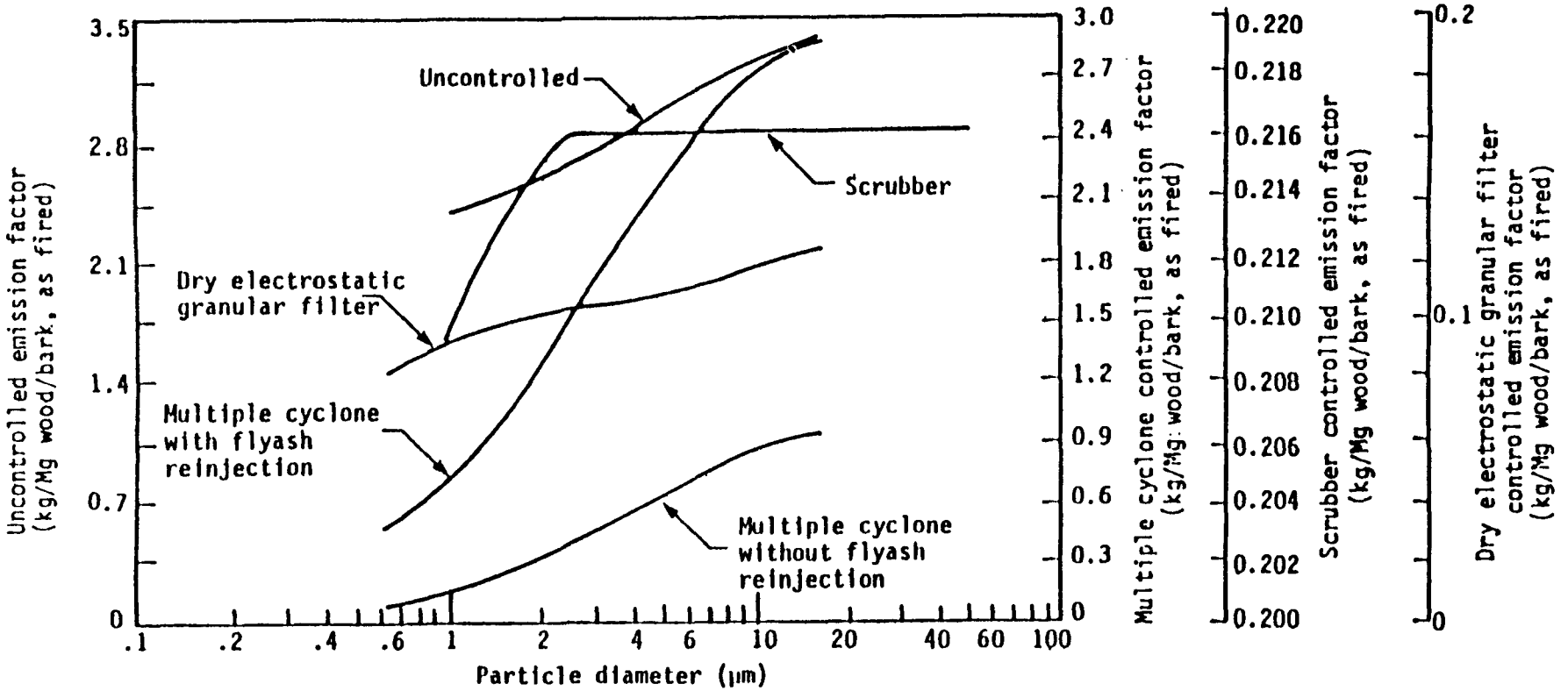


Figure 1.6-2. Cumulative size specific particulate matter emission factors for wood/bark-fired boilers.

Table 1.6-1. EMISSION FACTORS FOR PARTICULATE MATTER (PM), PARTICULATE MATTER LESS THAN 10 MICRONS (PM-10), AND LEAD FROM WOOD WASTE COMBUSTION[a]

Source Category (SCC)[b]	PM[c]			PM-10[d]			Lead[e]		
	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating
Bark-fired boilers (10100901, 10200901, 10200904, 10300901)									
Uncontrolled	23.5	47	B	8.4	17	D	1.4E-03	2.9E-03	D
Mechanical collector									
with flyash reinjection	7	14	B	5.5	11	D	ND[f]	ND	
without flyash reinjection	4.5	9.0	B	1.6	3.2	D			
Wet scrubber	1.5	2.9	D	1.3	2.5	D	ND	ND	
Wood/bark-fired boilers (10100902, 10200902, 10200905, 10300902)									
Uncontrolled	3.6	7.2	C	3.2	6.5	E	ND	ND	
Mechanical collector									
with flyash reinjection	3.0	6.0	C	2.7	5.5	E	1.6E-04[g]	3.2E-04[g]	D
without flyash reinjection	2.7	5.3	C	0.08	1.7	E	1.6E-04[g]	3.2E-04[g]	
Wet scrubber	0.24	0.48	D	0.23	0.47	E	1.8E-04	3.5E-04	D
Electrostatic precipitator	0.02	0.04	D	ND	ND		8.0E-05	1.6E-05	D
Wood-fired boilers (10100903, 10200903, 10200906, 10300903)									
Uncontrolled	4.4	8.8	C	ND	ND		ND	ND	
Mechanical collector									
without flyash reinjection	2.1	4.2	C	1.3[h]	2.6[h]	D	1.5E-04	3.1E-04	D
Electrostatic precipitator	0.08	0.17	D	ND	ND		5.5E-03	1.1E-03	D

[a]Units are kg of pollutant/Mg of wood waste burned and lbs. of pollutant/ton of wood waste burned. Emission factors are based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2,500 kcal/kg (4,\500 Btu/lb) higher heating value.
[b]SCC = Source Classification Code.
[c]References 11-15.
[d]References 13, 16.
[e]References 11, 13-15, 17.
[f]ND = No data.
[g]Due to lead's relative volatility, it is assumed that flyash reinjection does not have a significant effect on lead emissions following mechanical collectors.
[h]Based on one test in which 61 percent of emitted PM was less than 10 micrometer in size.

Table 1.6-2. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x), SULFUR OXIDES (SO_x), AND CARBON MONOXIDE (CO) FROM WOOD WASTE COMBUSTION[a]

Source Category (SCC)[b]	NO_x[c]			SO_x[d]			CO[e]		
	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating
Fuel cell/Dutch oven boiler (no SCC)	0.19 (0.0017-0.75)	0.38 (0.0033-1.5)	C	0.37 (0.005-0.1)	0.075 (0.01-0.2)	B	3.3 (0.33-11)	6.6 (0.65-21)	C
Stoker boilers (no SCC)	0.75 (0.33-1.8)	1.5 (0.66-3.6)	C	0.37 (0.005-0.1)	0.075 (0.01-0.2)	B	6.8 (0.95-40)	13.6 (1.9-80)	C
FBC boilers[f] (no SCC)	1.0	2.0	D	0.37 (0.005-0.1)	0.075 (0.01-0.2)	B	0.7 (0.24-1.2)	1.4 (0.47-2.4)	D

[a]Units are kg of pollutant/Mg of wood waste burned and lbs. of pollutant/ton of wood waste burned. Emission factors are based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2,500 kcal/kg (4,500 Btu/lb) higher heating value.

[b]SCC = Source Classification Code.

[c]References 12-14, 18-20. NO_x formation is primarily a function of wood nitrogen content. Higher values in the range (parentheses) should be used for wood nitrogen contents above a typical value of 0.08 weight percent, as fired.

[d]Reference 23. Lower limit of the range (in parentheses) should be used for wood and higher values for bark.

[e]References 11-15, 18, 24-26. Higher values in the range (in parentheses) should be used if combustion conditions are less than adequate, such as unusually wet wood or high air-to-fuel ratios.

[f]FBC = Fluidized bed combustion.

TABLE 1.6-3 EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC) AND CARBON DIOXIDE (CO_2) FROM WOOD WASTE COMBUSTION[a]

Source Category (SCC)[b]	TOC[c]			CO_2[d]		
	kg/Mg	lb/ton	Rating	kg/Mg	lb/ton	Rating
Fuel cell/Dutch oven boilers (no SCC)	0.09	0.18	C	1100	2100	B
Stoker boilers (no SCC)	0.11	0.22	C	1100	2100	B
FBC boilers[e] (no SCC)	ND[f]	ND		1100	2100	B

[a]Units are kg of pollutant/Mg of wood waste burned and lbs. of pollutant/ton of wood waste burned. Emission factros are b ased on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2500 kcal/kg (4500 Btu/lb) higher heating value.
[b]SCC = Source Classification Code.
[c]References 11, 14-15, 18. Emissions measured as total hydrocarbons, converted to kg carbon/Mg fuel (lb carbon/ton fuel).
[d]References 11, 14-15, 17, 27.
[e]FBC = Fluidized bed combustion.
[f]ND = No data.

Table 1.6-4 (Metric Units). EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM WOOD WASTE COMBUSTION[a]

Organic Compound[b]	Emission Factor Range[c] kg/Mg	Average Emission Factor kg/Mg	Emission Factor Rating
Phenols	3.2E-05-6.0E-05	1.9E-04	C
Acenaphthene	4.3E-08-2.1E-06	1.7E-06	C
Fluorene	8.5E-08-1.4E-05	4.8E-06	C
Phenanthrene	1.0E-06-9.0E-05	2.8E-05	C
Anthracene	4.3E-08-1.7E-04	1.9E-05	C
Fluoranthene	4.3E-08-4.3E-04	4.5E-05	C
Pyrene	2.1E-07-2.9E-05	8.5E-06	C
Benzo(a)anthracene	4.3E-08-3.2E-06	9.0E-07	C
Benzo(b+k)fluoranthene	1.7E-07-9.5E-05	1.9E-05	C
Benzo(a)pyrene	4.3E-08-1.5E-07	9.5E-08	D
Benzo(g,h,i)perylene	4.3E-08-1.7E-06	6.0E-07	C
Chrysene	4.3E-08-1.5E-04	2.1E-05	C
Indeno(1,2,3,c,d)pyrene	4.3E-08-3.0E-07	1.7E-07	D
Polychlorinated dibenzo-p-dioxins	1.5E-09-1.7E-08	6.0E-09[d,e]	C
Polychlorinated dibenzo-p-furans	2.3E-09-3.6E-08	1.5E-08[d,f]	C
Acenaphthylene	3.0E-07-3.4E-05	2.2E-05	C
Pyrene		4.5E-06[g]	D
Methyl anthracene		7.0E-05[g]	D
Acrolein		2.0E-06[g]	D
Solicyladehyde		1.1E-05[g]	D
Benzaldehyde		6.0E-06[g]	D
Formaldehyde	1.2E-04-1.6E-02	3.3E-03	C
Acetaldehyde	3.0E-05-1.2E-02	1.5E-03	C
Benzene	4.3E-05-7.0E-03	1.8E-03	C
Naphthalene	2.5E-05-2.9E-03	1.1E-03	C
2,3,7,8-Tetrachlorodibenzo-p-dioxin	1.1E-011-2.6E-011	1.8E-11	D

[a]Units are kg of pollutant/Mg of wood waste burned and lbs. of pollutant/ton wood waste burned. Emission factors are based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2500 kcal/kg higher heating value. Source Classification Codes are 10100901/02/03, 10200901/02/03/04/05/06/07, and 10300901/02/03.

[b]Pollutants in this table represent organic species measured for wood waste combustors. Other organic species may also have been emitted but were either not measured or were present at concentrations below analytical limits.

[c]References 11-15, 18, 26-28.

[d]Emission factors are for total dioxins and furans, not toxic equivalents.

[e]Excludes data from combustion of salt-laden wood. For salt-laden wood, emission factor is 6.5E-07 kg/Mg with a D rating.

[f]Excludes data from combustion of salt-laden wood. For salt-laden wood, emission factor is 2.8E-07 kg/Mg with a D rating.

[g]Based on data from one source test.

Table 1.6-5 (English Units). EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM WOOD WASTE COMBUSTION[a]

Organic Compound[b]	Emission Factor Range[c] lb/ton	Average Emission Factor lb/ton	Emission Factor Rating
Phenols	6.4E-05-1.2E-04	3.9E-04	C
Acenaphthene	8.6E-08-4.3E-06	3.4E-06	C
Fluorene	1.7E-07-2.8E-05	9.6E-06	C
Phenanthrene	2.0E-06-1.8E-04	5.7E-05	C
Anthracene	8.6E-08-3.5E-04	3.8E-05	C
Fluoranthene	8.6E-08-8.6E-04	9.0E-05	C
Pyrene	4.3E-07-5.9E-05	1.7E-05	C
Benzo(a)anthracene	8.6E-08-6.4E-06	1.8E-06	C
Benzo(b+k)fluoranthene	3.4E-07-1.9E-04	2.9E-05	C
Benzo(a)pyrene	8.6E-08-3.0E-07	1.9E-07	D
Benzo(g,h,i)perylene	8.6E-08-3.5E-06	1.2E-06	C
Chrysene	8.6E-08-3.0E-04	4.3E-05	C
Indeno(1,2,3,c,d)pyrene	8.6E-08-6.0E-07	3.4E-07	D
Polychlorinated dibenzo-p-dioxins	3.0E-09-3.3E-08	1.2E-08[d,e]	C
Polychlorinated dibenzo-p-furans	4.6E-09-7.2E-08	2.9E-08[d,f]	C
Acenaphthylene	6.0E-07-6.8E-05	4.4E-05	C
Pyrene		9.0E-06[g]	D
Methyl anthracene		1.4E-04[g]	D
Acrolein		4.0E-06[g]	D
Solicyladehyde		2.3E-05[g]	D
Benzaldehyde		1.2E-05[g]	D
Formaldehyde	2.3E-04-3.3E-02	6.6E-03	C
Acetaldehyde	6.1E-05-2.4E-02	3.0E-03	C
Benzene	8.6E-05-1.4E-02	3.6E-03	C
Naphthalene	5.0E-05-5.8E-03	2.3E-03	C
2,3,7,8-Tetrachlorodibenzo-p-dioxin	2.12E-011-5.11E-011	3.6E-11	D

[a]Units are kg of pollutant/Mg of wood waste burned and lbs. of pollutant/ton of wood waste burned. Emission factors are based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 4500 Btu/lb higher heating value. Source Classification Codes are 10100901/02/03, 10200901/02/03/04/05/06/07, and 10300901/02/03.

[b]Pollutants in this table represent organic species measured for wood waste combustors. Other organic species may also have been emitted but were either not measured or were present at concentrations below analytical limits.

[c]References 11-15, 18, 26-28.

[d]Emission factors are for total dioxins and furans, not toxic equivalents.

[e]Excludes data from combustion of salt-laden wood. For salt-laden wood, emission factor is 1.3E-06 lb/ton with a D rating.

[f]Excludes data from combustion of salt-laden wood. For salt-laden wood, emission factor is 5.5E-07 lb/ton with a D rating.

[g]Based on data from one source test.

Table 1.6-6 (Metric Units). EMISSION FACTORS FOR SPECIATED METALS FROM WOOD WASTE COMBUSTION[a]

Trace Element[b]	Emission Factor Range[c] kg/Mg	Average Emission Factor kg/Mg	Emission Factor Rating
Chromium (VI)	1.5E-05-2.9E-05	2.3E-05	D
Copper	7.0E-06-6.0E-04	9.5E-05	C
Zinc	4.9E-05-1.1E-02	2.2E-03	C
Barium		2.2E-03[d]	D
Potassium		3.9E-01[d]	D
Sodium		9.0E-03[d]	D
Iron	4.3E-04-3.3E-02	2.2E-02	D
Lithium		3.5E-05[d]	D
Boron		4.0E-04[d]	D
Chlorine		3.9E-03[d]	D
Vanadium		6.0E-05[d]	D
Cobalt[b]		6.5E-05[d]	D
Thorium		8.5E-06[d]	D
Tungsten		5.5E-06[d]	D
Dysprosium		6.5E-06[d]	D
Samarium		1.0E-05[d]	D
Neodymium		1.3E-05[d]	D
Praeseodymium		1.5E-05[d]	D
Iodine		8.0E-06[d]	D
Tin		1.5E-05[d]	D
Molybdenum		9.5E-05[d]	D
Niobium		1.7E-05[d]	D
Zirconium		1.7E-04[d]	D
Yttrium		2.8E-05[d]	D
Rubidium		6.0E-04[d]	D
Bromine		1.8E-04[d]	D
Germanium		1.7E-06[d]	D
Arsenic	7.0E-07-1.2E-04	4.4E-05	C
Cadmium	1.3E-06-2.7E-04	8.5E-06	C
Chromium (Total)	3.0E-06-2.3E-04	6.5E-05	C
Manganese	1.5E-04-2.6E-02	4.4E-03	C
Mercury	1.3E-06-1.0E-05	3.7E-06	C
Nickel	1.7E-05-2.9E-03	2.8E-04	C
Selenium	8.5E-06-9.0E-06	8.8E-06	D

[a]Units are kg of pollutant/Mg of wood waste burned and lbs. of pollutant/ton of wood waste burned. Emission factors are based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2500 kcal/kg higher heating value. Source Classification Codes are 10100901/02/03, 10200901/02/03/04/05/06/07, and 10300901/02/03.

[b]Pollutants in this table represent metal species measured for wood waste combustors. Other metal species may also have been emitted but were either not measured or were present at concentrations below analytical limits.

[c]References 11-15.

[d]Based on data from one source test.

Table 1.6-7 (English Units). EMISSION FACTORS FOR SPECIATED METALS FROM WOOD WASTE COMBUSTION[a]

Trace Element[b]	Emission Factor Range[c] lb/ton	Average Emission Factor lb/ton	Emission Factor Rating
Chromium (VI)	3.1E-05-5.9E-05	4.6E-05	D
Copper	1.4E-05-1.2E-03	1.9E-04	C
Zinc	9.9E-05-2.3E-02	4.4E-03	D
Barium		4.4E-03[d]	D
Potassium		7.8E-01[d]	D
Sodium		1.8E-02[d]	D
Iron	8.6E-04-8.7E-02	4.4E-02	D
Lithium		7.0E-05[d]	D
Boron		8.0E-04[d]	D
Chlorine		7.8E-03[d]	D
Vanadium		1.2E-04[d]	D
Cobalt		1.3E-04[d]	D
Thorium		1.7E-05[d]	D
Tungsten		1.1E-05[d]	D
Dysprosium		1.3E-05[d]	D
Samarium		2.0E-05[d]	D
Neodymium		2.6E-05[d]	D
Praeseodymium		3.0E-05[d]	D
Iodine		1.8E-05[d]	D
Tin		3.1E-05[d]	D
Molybdenum		1.9E-04[d]	D
Niobium		3.5E-05[d]	D
Zirconium		3.5E-04[d]	D
Yttrium		5.6E-05[d]	D
Rubidium		1.2E-03[d]	D
Bromine		3.9E-04[d]	D
Germanium		2.5E-06[d]	D
Arsenic	1.4E-06-2.4E-04	8.8E-05	C
Cadmium	2.7E-06-5.4E-04	1.7E-05	C
Chromium (Total)	6.0E-06-4.6E-04	1.3E-04	C
Manganese	3.0E-04-5.2E-02	8.9E-03	C
Mercury	2.6E-06-2.1E-05	6.5E-06	C
Nickel	3.4E-05-5.8E-03	5.6E-04	C
Selenium	1.7E-05-1.8E-05	1.8E-05	D

[a]Units are kg of pollutant/Mg of wood waste burned and lbs. of pollutant/ton of wood waste burned. Emission factors are based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 4500 Btu/lb higher heating value. Source Classification Codes are 10100901/02/03, 10200901/02/03/04/05/06/07, and 10300901/02/03.

[b]Pollutants in this table represent metal species measured for wood waste combustors. Other metal species may also have been emitted but were either not measured or were present at concentrations below analytical limits.

[c]References 11-15.

[d]Based on data from one source test.

Table 1.6-8. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR BARK-FIRED BOILERS[a]

EMISSION FACTOR RATING: D

Particle Size[b] (μm)	Cumulative Mass % ≤ stated size				Cumulative Emission Factor[c] [kg/Mg (lb/ton) bark, as fired]			
	Uncontrolled	Controlled			Uncontrolled	Controlled		
		Multiple Cyclone[d]	Multiple Cyclone[e]	Scrubber[f]		Multiple Cyclone[d]	Multiple Cyclone[e]	Scrubber[f]
15	42	90	40	92	10.1 (20.2)	6.3 (12.6)	1.8 (3.6)	1.32 (2.64)
10	35	79	36	87	8.4 (16.8)	5.5 (11.0)	1.62 (3.24)	1.25 (2.50)
6	28	64	30	78	6.7 (13.4)	4.5 (9.0)	1.35 (2.7)	1.12 (2.24)
2.5	21	40	19	56	5.0 (10.0)	2.8 (5.6)	0.86 (1.72)	0.81 (1.62)
1.25	15	26	14	29	3.6 (7.2)	1.8 (3.6)	0.63 (1.26)	0.42 (0.84)
1.00	13	21	11	23	3.1 (6.2)	1.5 (3.0)	0.5 (1.0)	0.33 (0.66)
0.625	9	15	8	14	2.2 (4.4)	1.1 (2.2)	0.36 (0.72)	0.20 (0.40)
TOTAL	100	100	100	100	24 (47)	7 (14)	4.5 (9.0)	1.44 (2.88)

[a]Reference 16. Emission factors are based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2,500 kcal/kg (4,500 Btu/lb) higher heating value. Source Classification Codes are 10100901, 10200901, 10200904, and 10300901.
[b]Expressed as aerodynamic equivalent diameter.
[c]Units are kg of pollutant/Mg of wood waste burned and lbs. of pollutant/ton of wood waste burned. Data limited to spreader stoker boilers.
[d]With flyash reinjection.
[e]Without flyash reinjection.
[f]Assumed control efficiency for scrubber is 94%.

Table 1.6-9. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR WOOD/BARK-FIRED BOILERS[a]

EMISSION FACTOR RATING: E

Particle Size[b] (μm)	Cumulative Mass % ≤ stated size					Cumulative Emission Factor[c] [kg/Mg (lb/ton) bark, as fired]				
	Uncontrolled[d]	Controlled				Uncontrolled[c]	Controlled			
		Multiple Cyclone[d]	Multiple Cyclone[e]	Scrubber[f]	DEGF		Multiple Cyclone[g]	Multiple Cyclone[e]	Scrubber[f]	DEGF[g]
15	94	96	35	98	77	3.38 (6.77)	2.88 (5.76)	0.95 (1.90)	0.216 (0.431)	0.123 (0.246)
10	90	91	32	98	74	3.24 (6.48)	2.73 (5.46)	0.86 (1.72)	0.216 (0.432)	0.118 (0.236)
6	86	80	27	98	69	3.10 (6.20)	2.40 (4.80)	0.73 (1.46)	0.216 (0.432)	0.110 (0.220)
2.5	76	54	16	98	65	2.74 (5.47)	1.62 (3.24)	0.43 (0.86)	0.216 (0.432)	0.104 (0.208)
1.25	69	30	84	96	61	2.48 (4.97)	0.90 (1.80)	0.22 (0.44)	0.211 (0.422)	0.098 (0.196)
1.00	67	24	6	95	58	2.41 (4.82)	0.72 (1.44)	0.16 (0.32)	0.209 (0.418)	0.093 (0.186)
0.625	ND	16	3	ND	51	ND	0.48 (0.96)	0.081 (0.162)	ND	0.082 (0.164)
TOTAL	100	100	100	100	100	3.6 (7.2)	3.0 (6.0)	2.7 (5.4)	0.24 (0.48)	0.16 (0.32)

[a]Reference 16. Emission factors are based on wet, as-fired wood waste with average properties of 50 weight percent moisture and 2500 kcal/kg (4500 Btu/lb) higher heating value. Source Classification Codes are 10100902, 10200902, 10200905, and 10300902.

[b]Expressed as aerodynamic equivalent diameter.

[c]Units are kg of pollutant/Mg of wood/bark burned and lbs. of pollutant/ton of wood/bark burned.

[d]From data on underfeed stokers. May also be used as size distribution for wood-fired boilers.

[e]From data on spreader stokers without flyash reinjection.

[f]From data on Dutch ovens. Assumed control efficiency is 94%.

[g]From data on spreader stokers with flyash reinjection.

[h]ND = No data.

References for Section 1.6

1. *Emission Factor Documentation for AP-42 Section 1.6--Wood Waste Combustion in Boilers*, Technical Support Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1993.

2. *Steam*, 38th Edition, Babcock and Wilcox, New York, NY, 1972.

3. *Atmospheric Emissions From the Pulp and Paper Manufacturing Industry*, EPA-450/1-73-002, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1973.

4. *C-E Bark Burning Boilers*, C-E Industrial Boiler Operations, Combustion Engineering, Inc., Windsor, CT, 1973.

5. *Nonfossil Fuel Fired Industrial Boilers - Background Information*, EPA-450/3-82-007, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.

6. *Control of Particulate Emissions From Wood-Fired Boilers*, EPA 340/1-77-026, U. S. Environmental Protection Agency, Washington, DC, 1977.

7. *Background Information Document For Industrial Boilers*, EPA 450/3-82-006a, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.

8. E. F. Aul, Jr. and K. W. Barnett, "Emission Control Technologies For Wood-Fired Boilers", Presented at the Wood Energy Conference, Raleigh, NC, October 1984.

9. G. Moilanen, K. Price, C. Smith, and A. Turchina, "Noncatalytic Ammonia Injection For NO_x Reduction on a Waste Wood Fired Boiler", Presented at the 80th Annual Meeting of the Air Pollution Control Association, New York, NY, June 1987.

10. "Information on the Sulfur Content of Bark and Its Contribution to SO_2 Emissions When Burned as a Fuel", H. Oglesby and R. Blosser, *Journal of the Air Pollution Control Agency*, 30(7):769-772, July 1980.

11. Written communication from G. Murray, California Forestry Association, Sacramento, CA to E. Aul, Edward Aul & Associates, Inc., Chapel Hill, NC, Transmittal of Wood Fired Boiler Emission Test, April, 24, 1992.

12. *Hazardous Air Emissions Potential From a Wood-Fired Furnace (and Attachments)*, A. J. Hubbard, Wisconsin Department of Natural Resources, Madison, WI, July 1991.

13. *Environmental Assessment of a Wood-Waste-Fired Industrial Watertube Boiler*, EPA Contract No. 68-02-3188, Acurex Corporation, Mountain View, CA, March 1984.

14. *Evaluation Test on a Wood Waste Fired Incinerator at Pacific Oroville Power Inc.*, Test Report No. C-88-050, California Air Resources Broad, Sacramento, CA, May 1990.

References for Section 1.6 (Continued)

15. *Evaluation Test on Twin Fluidized Bed Wood Waste Fueled Combustors Located in Central California*, Test Report No. C-87-042, California Air Resources Board, Sacramento, CA, February, 1990.

16. *Inhalable Particulate Source Category Report for External Combustion Sources*, EPA Contract No. 68-02-3156, Acurex Corporation, Mountain View, CA, January 1985.

17. *Emission Test Report, Owens-Illinois Forest Products Division, Big Island, Virginia*, EMB Report 80-WFB-2, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1980.

18. *National Dioxin Study Tier 4, Combustion Sources: Final Test Report, Site 7, Wood Fired Boiler WFB-A*, EPA-450/4-84-014p, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1987.

19. *Air Pollutant Emission Factors*, APTD-0923, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1970.

20. *A Study of Nitrogen Oxides Emissions From Wood Residue Boilers*, Technical Bulletin No. 102, National Council of the Paper Industry for Air and Stream Improvement, New York, NY, November 1979.

21. R. A. Kester, *Nitrogen Oxide Emissions From a Pilot Plant Spreader Stoker Bark Fired Boiler*, Department of Civil Engineering, University of Washington, Seattle, WA, December 1979.

22. A. Nunn, *NO_x Emission Factors For Wood Fired Boilers*, EPA-600/7-79-219, U. S. Environmental Protection Agency, September 1979.

23. H. S. Oglesby and R. O. Blosser, "Information on the Sulfur Content of Bark and Its Contribution to SO_2 Emissions When Burned as a Fuel", *Journal of the Air Pollution Control Agency*, 30(7):769-772, July 1980.

24. *Carbon Monoxide Emissions From Selected Combustion Sources Based on Short-Term Monitoring Records*, Technical Bulletin No. 416, National Council of the Paper Industry For Air and Stream Improvement, New York, NY, January 1984.

25. *Volatile Organic Carbon Emissions From Wood Residue Fired Power Boilers in the Southeast*, Technical Bulletin No. 455, National Council of the Paper Industry For Air and Stream Improvement, New York, NY, April 1985.

26. *A Study of Formaldehyde Emissions From Wood Residue-Fired Boilers*, Technical Bulletin No. 622, National Council of the Paper Industry For Air and Stream Improvement, New York, NY, January 1992.

References for Section 1.6 (Continued)

27. *Emission Test Report, St. Joe Paper Company, Port St. Joe, Florida*, EMB Report 80-WFB-5, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1980.

28. *A Polycyclic Organic Materials Study For Industrial Wood-Fired Boilers*, Technical Bulletin No. 400, National Council of the Paper Industry For Air and Stream Improvement, New York, NY, May 1983.

1.7 LIGNITE COMBUSTION

1.7.1 General[1-4]

Lignite is a coal in the early stages of coalification, with properties intermediate to those of bituminous coal and peat. The two geographical areas of the U.S. with extensive lignite deposits are centered in the States of North Dakota and Texas. The lignite in both areas has a high moisture content (30 to 40 weight percent) and a low heating value, [1,400 to 1,900 kcal/kg (2,500 to 3,400 Btu/lb), on a wet basis]. Consequently, lignite is burned near where it is mined. A small amount is used in industrial and domestic situations, but lignite is mainly used for steam/electric production in power plants. Lignite combustion has advanced from small stokers and the first pulverized coal (PC) and cyclone-fired units to large (greater than 800 MW) PC power plants.

The major advantages of firing lignite are that it is relatively abundant (in the North Dakota and Texas regions), relatively low in cost, and low in sulfur content. The disadvantages are that more fuel and larger facilities are necessary to generate a unit of power than is the case with bituminous coal. The reasons for this are: (1) lignite's higher moisture content means that more energy is lost in evaporating water, which reduces boiler efficiency; (2) more energy is required to grind lignite to combustion-specified size, especially in PC-fired units; (3) greater tube spacing and additional soot blowing are required because of lignite's higher ash fouling tendencies; and (4) because of its lower heating value, more lignite must be handled to produce a given amount of power. Lignite usually is not cleaned or dried before combustion (except for incidental drying in the crusher or pulverizer and during transport to the burner). No major problems exist with the handling or combustion of lignite when its unique characteristics are taken into account.

1.7.2 Emissions [2-11,17]

The major pollutants generated from firing lignite, as with any coal, are particulate matter (PM), sulfur oxides (SO_x), and nitrogen oxides (NO_x). Emissions rates of organic compounds and carbon monoxide (CO) are much lower than those for the major pollutants under normal operating conditions.

Emission levels for PM appear most dependent on the firing configuration of the boiler. Pulverized coal-fired units and spreader stokers fire much or all of the lignite in suspension; they emit a greater quantity of flyash per unit of fuel burned than do cyclones and other stokers. Cyclone furnaces collect much of the ash as molten slag in the furnace itself. Stokers (other than spreader) retain a large fraction of the ash in the fuel bed and bottom ash.

The NO_x emissions from lignite combustion are mainly a function of the boiler design, firing configuration, and excess air level. Stokers produce lower NO_x levels than PC units and cyclones, mainly because most stokers are relatively small and have lower peak flame temperatures. The boilers constructed since implementation of the 1971 and 1979 new source performance standards (40 Code of Federal Regulations, Part 60, Subparts D and Da respectively) have NO_x controls integrated into the boiler design and have comparable NO_x emission levels to the small stokers. In most boilers, regardless of firing configuration, lower excess combustion air results in lower NO_x emissions.

However, lowering the amount of excess air in a lignite-fired boiler can also affect the potential for ash fouling.

The rate of SO_x emissions from lignite combustion are a function of the alkali (especially sodium) content of the ash. For combustion of most fossil fuels, over 90 percent of the fuel sulfur is emitted as sulfur dioxide (SO_2) because of the low alkali content of the fuels. By contrast, a significant fraction of the sulfur in lignite reacts with alkaline ash components during combustion and is retained in the boiler bottom ash and flyash. Tests have shown that less than 50 percent of the available sulfur may be emitted as SO_2 when a high-sodium lignite is burned, whereas more than 90 percent may be emitted from a low-sodium lignite. As an approximate average, about 75 percent of the lignite sulfur will be emitted as SO_2; the remainder will be retained in the ash as various sulfate salts.

1.7.3 Controls[2,11-17]

Most lignite-fired utility boilers are equipped with electrostatic precipitators (ESPs) with collection efficiencies as high as 99.5 percent for total PM. Older and smaller ESPs have lower collection efficiencies of approximately 95 percent for total PM. Older industrial and commercial units also may be equipped with cyclone collectors that normally achieve 60 to 80 percent collection efficiency for total PM.

Flue gas desulfurization (FGD) systems (comparable to those used on bituminous coal-fired boilers) are in current operation on several lignite-fired utility boilers. Flue gases are treated through wet 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_x absorbent is regenerated and reused). Wet systems generally use alkali slurries as the SO_x absorption medium and can reduce SO_x emissions by 90 percent or more. Spray dryers (or dry scrubbers) spray a solution or slurry of alkaline material into a reaction vessel as a fine mist that mixes with the flue gas. The SO_2 reacts with the alkaline mist to form salts. The solids from the spray dryer and the salts formed are collected in a particulate control device.

Over 50 percent reduction of NO_x emissions can be achieved by changing the burner geometry, controlling air flow in the furnace, or making other changes in operating procedures. Overfire air and low NO_x burners are two demonstrated NO_x control techniques for lignite combustion.

Baseline emission factors for NO_x, SO_x, and CO are presented in Tables 1.7-1 and 1.7-2. Baseline emission factors for total PM and nitrous oxide (N_2O) are given in Table 1.7-3. Specific emission factors for the cumulative particle size distributions are provided in Tables 1.7-4 and 1.7-5. Uncontrolled and controlled size-specific emission factors are presented in Figures 1.7-1 and 1.7-2. Lignite combustion and bituminous coal combustion are quite similar with respect to emissions of carbon dioxide (CO_2) and organic compounds. As a result, the bituminous coal emission factors for these pollutants presented in Section 1.1 of this document may also be used to estimate emissions from lignite combustion.

Emission factors for trace elements from uncontrolled lignite combustion are summarized in Tables 1.7-6 and 1.7-7, based on currently available data.

Controlled emission factors for NO_x, CO, and PM are presented in Tables 1.7-8 and 1.7-9. Controlled SO_2 emissions will depend primarily of applicable regulations and FGD equipment performance, if applicable. *Section 1.1 contains a discussion of* FGD performance capabilities which is also applicable to lignite-fired boilers. Controlled emission factors for selected hazardous air pollutants are provided in Tables 1.7-10 and 1.7-11.

Table 1.7-1 (Metric Units). EMISSION FACTORS FOR SULFUR OXIDES (SO_x), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM UNCONTROLLED LIGNITE COMBUSTION[a]

Firing Configuration (SCC)[b]	SO_x[c]		NO_x[d]		CO[e]	
	Emission Factor	Rating	Emission Factor	Rating	Emission Factor	Rating
Pulverized coal, dry bottom, tangential (SCC 10100302)	15S[e]	C	3.7	C		
Pulverized coal, dry bottom, wall fired (SCC 10100301)	15S	C	5.6	C	0.13	C
Cyclone (SCC 10100303)	15S	C	6.3	C		
Spreader stoker (SCC 10100306)	15S	C	2.9	C		
Other stoker (SCC 10100304)[e]	15S	C	2.9	C		
Atmospheric fluidized bed (no SCC)	3S	D	1.8	C	0.08	C

[a]Units are kg of pollutant/Mg of fuel burned.
[b]SCC= Source Classification Code.
[c]Reference 2.
[d]References 2-3, 7-8, 15-16.
[e]References 7, 16.
[e]S= Weight % sulfur content of lignite, wet basis.
For high sodium ash (Na_2O > 8%), use 11S.
For low sodium ash (Na_2O < 2%), use 17S.
If ash sodium content is unknown, use 15S.

Table 1.7-2 (English Units). EMISSION FACTORS FOR SULFUR OXIDES (SO_x), NITROGEN OXIDES (NO_x), AND CARBON MONOXIDE (CO) FROM UNCONTROLLED LIGNITE COMBUSTION[a]

Firing Configuration (SCC)[b]	SO_x[c]		NO_x[d]		CO[e]	
	Emission Factor	Rating	Emission Factor	Rating	Emission Factor	Rating
Pulverized coal, dry bottom, tangential (SCC 10100302)	30S[e]	C	7.3	C		
Pulverized coal, dry bottom, wall fired (SCC 10100301)	30S	C	11.1	C	0.25	C
Cyclone (SCC 10100303)	30S	C	12.5	C		
Spreader stoker (SCC 10100306)	30S	C	5.8	C		
Other stoker (SCC 10100304)[f]	30S	C	5.8	C		
Atmospheric fluidized bed (no SCC)	30S	C	3.6	C	0.15	C

[a]Units are lb. of pollutant/ton of fuel burned.
[b]SCC= Source Classification Code.
[c]Reference 2.
[d]References 2-3, 7-8, 15-16.
[e]References 7, 16.
[f]S= Weight % sulfur content of lignite, wet basis.
For high sodium ash (Na_2O > 8%), use 22S.
For low sodium ash (Na_2O < 2%), use 34S.
If ash sodium content is unknown, use 30S.

Table 1.7-3. EMISSION FACTORS FOR PARTICULATE MATTER (PM) AND NITROUS OXIDE (N_2O) FROM LIGNITE COMBUSTION[a]

Firing Configuration (SCC)	PM[b]		N_2O[c]	
	Emission Factor	Rating	Emission Factor	Rating
Pulverized coal, dry bottom, tangential (SCC 10100302)	3.3A (6.5A)	E		
Pulverized coal, dry bottom, wall fired (SCC 10100301)	2.6A (5.1A)	E		
Cyclone (SCC 10100303)	3.4A (6.7A)	C		
Spreader stoker (SCC 10100306)	4.0A (8.0A)	E		
Other stoker (SCC 10100304)	1.7A (3.4A)	E		
Atmospheric fluidized bed			1.2 (2.5)	E

[a]Units are kg of pollutant/Mg of fuel burned and lb. of pollutant/ton of fuel burned.
SCC= Source Classification Code.
[b]References 5-6, 12, 14. A = weight % ash content of lignite, wet basis.
[c]Reference 18.

Table 1.7-4. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR BOILERS FIRING PULVERIZED LIGNITE[a]

EMISSION FACTOR RATING: E

Particle Size[b] μm	Cumulative Mass % ≤ stated size		Cumulative Emission Factor[c]	
	Uncontrolled	Multiple Cyclone Controlled	Uncontrolled	Multiple Cyclone Controlled[d]
15	51	77	1.7A (3.4A)	0.51A (1.0A)
10	35	67	1.2A (2.3A)	0.44A (0.88A)
6	26	57	0.86A (1.7A)	0.38A (0.75A)
2.5	10	27	0.33A (0.66A)	0.18A (0.36A)
1.25	7	16	0.23A (0.47A)	0.11A (0.21A)
1.00	6	14	0.20A (0.40A)	0.093A (0.19A)
0.625	3	8	0.10A (0.19A)	0.053A (0.11A)
TOTAL			3.3A (6.6A)	0.66A (1.3A)

[a]Reference 13. Based on tangential-fired units. For wall-fired units, multiply emission factors in the table by 0.79.
[b]Expressed as aerodynamic equivalent diameter.
[c]Units are kg of pollutant/Mg of fuel burned and lb. of pollutant/ton of fuel burned.
A = weight % ash content of coal, wet basis.
[d]Estimated control efficiency for multiple cyclone is 80%.

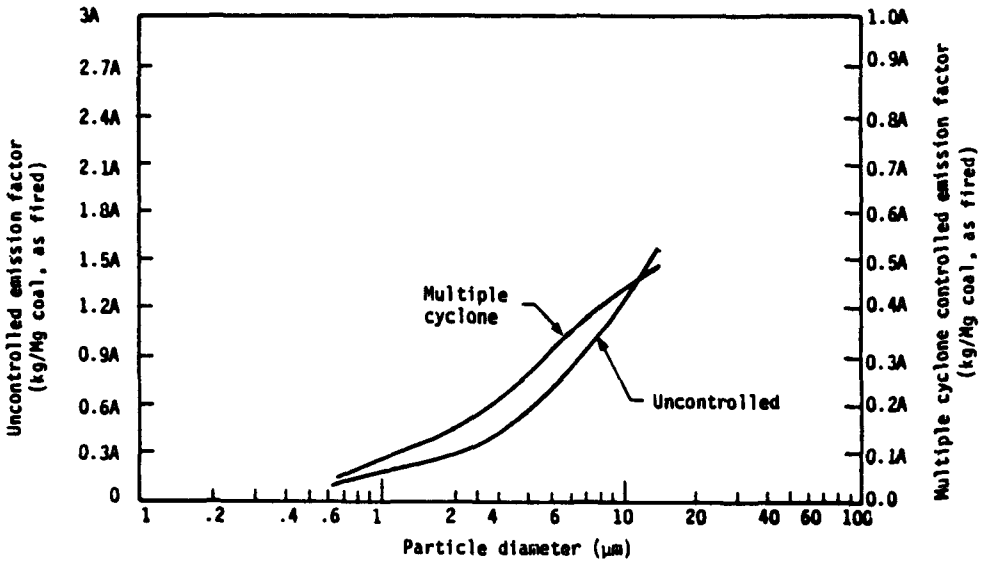


Figure 1.7-1. Cumulative size specific emission factors for boilers firing pulverized lignite.

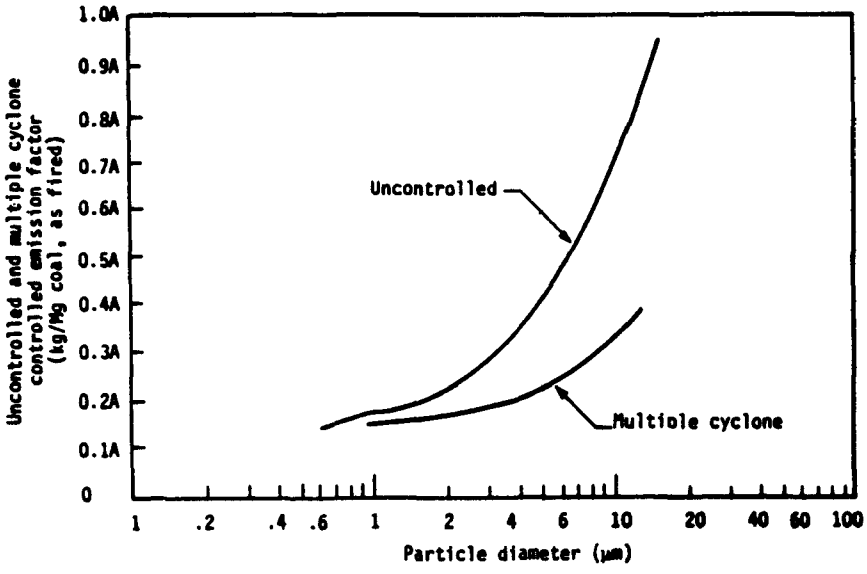


Figure 1.7-2. Cumulative size specific emission factors for lignite-fired spreader stokers.

Table 1.7-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE SPECIFIC EMISSION FACTORS FOR LIGNITE FIRED SPREADER STOKERS[a]

EMISSION FACTOR RATING: E

Particle Size[b] μm	Cumulative Mass % ≤ stated size		Cumulative Emission Factor[c]	
	Uncontrolled	Multiple Cyclone Controlled	Uncontrolled	Multiple Cyclone Controlled[d]
15	28	55	1.1A (2.2A)	0.44A (0.88A)
10	20	41	0.80A (1.6A)	0.33A (0.66A)
6	14	31	0.56A (1.1A)	0.25A (0.50A)
2.5	7	26	0.28A (0.56A)	0.21A (0.42A)
1.25	5	23	0.20A (0.40A)	0.18A (0.37A)
1.00	5	22	0.20A (0.40A)	0.18A (0.35A)
0.625	4	e	0.16A (0.33A)	e
TOTAL			4.0A (8.0A)	0.80A (1.6A)

[a]Reference 13.
[b]Expressed as aerodynamic equivalent diameter.
[c]Units are kg of pollutant/Mg of fuel burned and lb. of pollutant/ton of fuel burned.
A = weight % ash content of lignite, wet basis.
[d]Estimated control efficiency for multiple cyclone is 80%.
[e]Insufficient data.

Table 1.7-6 (Metric Units). EMISSION FACTORS FOR TRACE ELEMENTS FROM UNCONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	pg/J						
	As	Be	Cd	Cr	Mn	Hg	Ni
Pulverized, wet bottom (no SCC)	1175	56	21-33	525-809	1917-7065	9	70-504
Pulverized, dry bottom (no SCC)	598	56	21	645-809	7043	9	404-504
Cyclone furnace (SCC 10100303)	101-272	56	13	109-809	1635	9	68-504
Stoker, configuration unknown (no SCC)		51			5130	9	303-504
Spreader stoker (SCC 10100306)	231-473		10-20	486-809			
Traveling grate (overfed) stoker (SCC 10100304)	473-904		20-39				

[a]References 19-20. Units are picograms (10^{-12}) of pollutant/Joule of fuel burned. SCC= Source Classification Code.

Table 1.7-7 (English Units). EMISSION FACTORS FOR TRACE ELEMENTS FROM UNCONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	lb/10^{12} Btu						
	As	Be	Cd	Cr	Mn	Hg	Ni
Pulverized (SCC 10100301)							
Pulverized, wet bottom (no SCC)	2730	131	49-77	1220-1880	4410-16,250	21	154-1160
Pulverized, dry bottom (no SCC)	1390	131	49	1500-1880	16,200	21	928-1160
Cyclone furnace (SCC 10100303)	235-632	130	31	253-1880	3760	21	157-1160
Stoker configuration unknown (no SCC)		118			11800	21	
Spreader stoker (SCC 10100306)	538-1100		23-47	1130-1880			696-1160
Traveling grate (overfed) stoker (SCC 10100304)	1100-2100		47-90				

[a]References 19-20. Units are lb. of pollutant/10^{12}Btu of fuel burned. SCC = Source Classification Code.

Table 1.7-8. CONTROLLED EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM CONTROLLED LIGNITE COMBUSTION[a]

Firing Configuration (SCC)	NO_x[b]		CO[c]	
	Emission Factor kg/Mg (lb/ton)	Rating	Emission Factor kg/Mg (lb/ton)	Rating
Pulverized coal, dry bottom, tangential overfire air (no SCC)	3.3 (6.6)	C	0.05 (0.10)	D
Pulverized coal, dry bottom, tangential overfire air/low NO_x burners (no SCC)	2.3 (4.6)	C	0.24 (0.48)	D

[a]Units are kg of pollutant/Mg of fuel burned and lb. of pollutant/ton of fuel burned.
SCC = Source Classification Code.
[b]Reference 15, 16.
[c]References 15.

Table 1.7-9. EMISSION FACTORS FOR PARTICULATE MATTER (PM) EMISSIONS FROM CONTROLLED LIGNITE COMBUSTION[a]

Firing Configuration (SCC)	Control Device	PM	
		Emission Factor	Rating
Subpart D Boilers, Pulverized coal, Tangential and wall-fired (no SCC)	Baghouse	0.08A (0.16A)	C
	Wet scrubber	0.05A (0.10A)	C
Subpart Da Boilers, Pulverized coal, Tangential fired (no SCC)	Wet scrubber	0.01A (0.02A)	C
Atmospheric fluidized bed	Limestone addition	0.03A (0.06A)	D

[a]Reference 15-16. A = weight % ash content of lignite, wet basis.
Units are kg of pollutant/Mg of fuel burned and lb. of pollutant/ton of fuel burned.
SCC = Source Classification Code.

Table 1.7-10 (Metric Units). EMISSION FACTORS FOR TRACE METALS AND POLYCYCLIC ORGANIC MATTER (POM) FROM CONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Control Device	Emission Factor, pg/J		
		Cr	Mn	POM
Pulverized coal (SCC 10100301)	Multi-cyclones	29-32		
	ESP	8.6		
	High efficiency cold-side ESP			0.99
Pulverized wet bottom (no SCC)	ESP		15	
Pulverized dry bottom (no SCC)	Multi-cyclones			0.78-7.9[b]
	ESP		18	1.1[b]
Cyclone furnace (SCC 10100303)	ESP	<3.3	57	0.05[c]-0.68[b]
	Multi-cyclones		710	
Stoker, configuration unknown (no SCC)	Multi-cyclones	13	47	
	ESP	<2.3		
Spreader stoker (SCC 10100306)	Multi-cyclones			6.3[c]

[a]References 19-20. Units are picograms (10^{-12}) of pollutant/Joule of fuel burned.
SCC = Source Classification Code.
[b]Primarily trimethyl propenyl naphthalene.
[c]Primarily biphenyl.

Table 1.7-11 (English Units). EMISSION FACTORS FOR TRACE METALS AND POLYCYCLIC ORGANIC MATTER (POM) FROM CONTROLLED LIGNITE COMBUSTION[a]

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Control Device	Emission Factor, lb/10^{12}Btu		
		Cr	Mn	POM
Pulverized coal (SCC 10100301)	Multi-cyclones	67-74		
	ESP	20		
	High efficiency cold-side ESP			2.3
Pulverized wet bottom (no SCC)	ESP		34	
Pulverized dry bottom (no SCC)	Multi-cyclones			1.8-18[b]
	ESP		42	2.6[b]
Cyclone furnace (SCC 10100303)	ESP	<28	133	0.11[c]-1.6[b]
	Multi-cyclones		1700	
Stoker, configuration unknown (no SCC)	Multi-cyclones	30	110	
	ESP	<5.4		
Spreader stoker (SCC 10100306)	Multi-cyclones			15[c]

[a]References 19-20. Units are lb. of pollutant/10^{12}Btu of fuel burned.
SCC = Source Classification Code.
[b]Primarily trimethyl propenyl naphthalene.
[c]Primarily biphenyl.

References for Section 1.7

1. *Kirk-Othmer Encyclopedia of Chemical Technology, Second Edition, Volume 12*, John Wiley and Sons, New York, NY, 1967.

2. G. H. Gronhovd, et al., "Some Studies on Stack Emissions from Lignite Fired Powerplants", Presented at the 1973 Lignite Symposium, Grand Forks, ND, May 1973.

3. *Standards Support and Environmental Impact Statement: Promulgated Standards of Performance for Lignite Fired Steam Generators: Volumes I and II*, EPA-450/2-76-030a and 030b, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1976.

4. *1965 Keystone Coal Buyers Manual*, McGraw-Hill, Inc., New York, NY, 1965.

5. *Source Test Data on Lignite-Fired Power Plants*, North Dakota State Department of Health, Bismarck, ND, December 1973.

6. G. H. Gronhovd, et al., "Comparison of Ash Fouling Tendencies of High and Low Sodium Lignite from a North Dakota Mine", Proceedings of the American Power Conference, Volume XXVIII, 1966.

7. A. R. Crawford, *et al., Field Testing: Application of Combustion Modification to Control NO_x Emissions from Utility Boilers*, EPA-650/2-74-066, U. S. Environmental Protection Agency, Washington, DC, June 1974.

8. *Nitrogen Oxides Emission Measurements for Three Lignite Fired Power Plants, Contract No. 68-02-1401 and 68-02-1404*, Office Of Air Quality Planning And Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1974.

9. *Coal Fired Power Plant Trace Element Study, A Three Station Comparison*, U. S. Environmental Protection Agency, Denver, CO, September 1975.

10. C. Castaldini, and M. Angwin, *Boiler Design and Operating Variables Affecting Uncontrolled Sulfur Emissions from Pulverized Coal Fired Steam Generators*, EPA-450/3-77-047, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1977.

11. C. C. Shih, *et al., Emissions Assessment of Conventional Stationary Combustion Systems, Volume III: External Combustion Sources for Electricity Generation*, EPA Contract No. 68-02-2197, TRW Inc., Redondo Beach, CA, November 1980.

12. *Source Test Data on Lignite-Fired Cyclone Boilers*, North Dakota State Department of Health, Bismarck, ND, March 1982.

13. *Inhalable Particulate Source Category Report for External Combustion Sources*, EPA Contract No. 68-02-3156, Acurex Corporation, Mountain View, CA, January 1985.

14. Personal communication dated September 18, 1981, Letter from North Dakota Department of Health to Mr. Bill Lamson of the U. S. Environmental Protection Agency, Research Triangle Park, NC, conveying stoker data package.

References for Section 1.7 (Continued)

15. *Source Test Data on Lignite-Fired Power Plants*, North Dakota State Department of Health, Bismarck, ND, April 1992.

16. *Source Test Data on Lignite-Fired Power Plants*, Texas Air Control Board, Austin, TX, April 1992.

17. Honea, et al., "The Effects of Overfire Air and Low Excess Air on NO_x Emissions and Ash Fouling Potential for a Lignite-Fired Boiler", Proceedings of the American Power Conference, Volume 40, 1978.

18. M. D. Mann, et al., "Effect of Operating Parameters on N_2O Emissions in a 1-MW CFBC," Presented at the 8th Annual Pittsburgh Coal Conference, Pittsburgh, PA, October, 1991.

19. G. W. Brooks, M. B. Stockton, K. Kuhn, and G. D. Rives, Radian Corporation, *Locating and Estimating Air Emission from Source of Polycyclic Organic Matter (POM)*, EPA-450/4-84-007p, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1988.

20. J. C. Evans, et al., *Characterization of Trace Constituents at Canadian Coal-Fired Plants, Phase I: Final Report and Appendices*, Report for the Canadian Electrical Association, R&D, Montreal, Quebec, Contract Number 001G194.

1.8 BAGASSE COMBUSTION IN SUGAR MILLS

1.8.1 Process Description[1-5]

Bagasse is the matted cellulose fiber residue from sugar cane that has been processed in a sugar mill. Previously, bagasse was burned as means of solid waste disposal. However, as the cost of fuel oil, natural gas, and electricity have increased, the definition of bagasse has changed from refuse to a fuel.

The U.S. sugar cane industry is located in the tropical and subtropical regions of Florida, Texas, Louisiana, Hawaii, and Puerto Rico. Except for Hawaii, where sugar cane production takes place year round, sugar mills operate seasonally from 2 to 5 months per year.

Sugar cane is a large grass with a bamboo-like stalk that grows 8 to 15 feet tall. Only the stalk contains sufficient sucrose for processing into sugar. All other parts of the sugar cane (i.e., leaves, top growth and roots) are termed "trash." The objective of harvesting is to deliver the sugar cane to the mill with a minimum of trash or other extraneous material. The cane is normally burned in the field to remove a major portion of the trash and to control insects and rodents. See Section 11.1 for methods to estimate these emissions. The three most common methods of harvesting are hand cutting, machine cutting, and mechanical raking. The cane that is delivered to a particular sugar mill will vary in trash and dirt content depending on the harvesting method and weather conditions. Inside the mill, cane preparation for extraction usually involves washing the cane to remove trash and dirt, chopping, and then crushing. Juice is extracted in the milling portion of the plant by passing the chopped and crushed cane through a series of grooved rolls. The cane remaining after milling is bagasse.

Bagasse is a fuel of varying composition, consistency, and heating value. These characteristics depend on the climate, type of soil upon which the cane is grown, variety of cane, harvesting method, amount of cane washing, and the efficiency of the milling plant. In general, bagasse has a heating value between 1,700 and 2,200 kcal/kg (3,000 and 4,000 Btu/lb) on a wet, as-fired basis. Most bagasse has a moisture content between 45 and 55 percent by weight.

Fuel cells, horseshoe boilers, and spreader stoker boilers are used to burn bagasse. Horseshoe boilers and fuel cells differ in the shapes of their furnace area but in other respects are similar in design and operation. In these boilers (most common among older plants), bagasse is gravity-fed through chutes and piles onto a refractory hearth. Primary and overfire combustion air flows through ports in the furnace walls; burning begins on the surface pile. Many of these units have dumping hearths that permit ash removal while the unit is operating.

In more-recently built sugar mills, bagasse is burned in spreader stoker boilers. Bagasse feed to these boilers enters the furnace through a fuel chute and is spread pneumatically or mechanically across the furnace, where part of the fuel burns while in suspension. Simultaneously, large pieces of fuel are spread in a thin, even bed on a stationary or moving grate. The flame over the grate radiates heat back to the fuel to aid combustion. The combustion area of the furnace is lined with heat exchange tubes (waterwalls).

1.8.2 Emissions and Controls[1-3]

The most significant pollutant emitted by bagasse-fired boilers is particulate matter, caused by the turbulent movement of combustion gases with respect to the burning bagasse and resultant ash. Emissions of SO_2 and NO_x are lower than conventional fossil fuels due to the characteristically low levels of sulfur and nitrogen associated with bagasse.

Auxiliary fuels (typically fuel oil or natural gas) may be used during startup of the boiler or when the moisture content of the bagasse is too high to support combustion. If fuel oil is used during these periods, SO_2 and NO_x emissions will increase. Soil characteristics such as particle size can affect the magnitude of PM emissions from the boiler. Mill operations can also influence the bagasse ash content by not properly washing and preparing the cane. Upsets in combustion conditions can cause increased emissions of carbon monoxide (CO) and unburned organics, typically measured as volatile organic compounds (VOCs) and total organic compounds (TOCs).

Mechanical collectors and wet scrubbers are commonly used to control particulate emissions from bagasse-fired boilers. Mechanical collectors may be installed in single cyclone, double cyclone, or multiple cyclone (i.e., multiclone) arrangements. The reported PM collection efficiency for mechanical collectors is 20 to 60 percent. Due to the abrasive nature of bagasse fly ash, mechanical collector performance may deteriorate over time due to erosion if the system is not well maintained.

The most widely used wet scrubbers for bagasse-fired boilers are impingement and venturi scrubbers. Impingement scrubbers normally operate at gas-side pressure drops of 5 to 15 inches of water; typical pressure drops for venturi scrubbers are over 15 inches of water. Impingement scrubbers are in greater use due to lower energy requirements and fewer operating and maintenance problems. Reported PM collection efficiencies for both scrubber types are 90 percent or greater.

Gaseous emissions (e.g., SO_2, NO_x, CO, and organics) may also be absorbed to a significant extent in a wet scrubber. Alkali compounds are sometimes utilized in the scrubber to prevent low pH conditions. If CO_2-generating compounds (such as sodium carbonate or calcium carbonate) are used, CO_2 emissions will increase.

Fabric filters and electrostatic precipitators have not been used to a significant extent for controlling PM from bagasse-fired boilers due to potential fire hazards (fabric filters) and relatively higher costs (both devices).

Emission factors and emission factor ratings for bagasse-fired boilers are shown in Table 1.8-1 (metric units) and Table 1.8-2 (English units).

Fugitive dust may be generated by truck traffic and cane handling operations at the sugar mill. Particulate matter emissions from these sources may be estimated by consulting Section 11.2.

Table 1.8-1 (Metric Units). EMISSION FACTORS FOR BAGASSE-FIRED BOILERS[a]

Pollutant	Emission factor, g/kg steam[b]	Emission factor, kg/Mg bagasse[c]	Rating
Particulate matter[d]			
Uncontrolled	3.9	7.8	C
Controlled			
Mechanical collector	2.1	4.2	D
Wet scrubber	0.4	0.8	B
PM-10[d]			
Controlled			
Wet scrubber	0.34	0.68	D
Carbon dioxide			
Uncontrolled[e]	390	780	A
Nitrogen oxides			
Uncontrolled[f]	0.3	0.6	C
Polycyclic organic matter			
Uncontrolled[g]	2.5E-4	5.0E-4	D

[a]Source Classification Code is 10201101.
[b]Units are gram of pollutant/kg of steam produced, where 1 kg of wet bagasse fired produces 2 kg of steam.
[c]Units are kg of pollutant/Mg of wet, as-fired bagasse containing approximately 50 percent moisture, by weight.
[d]References 2, 6-14. Includes only filterable PM (i.e., that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
[e]References 6-14. CO_2 emissions will increase following a wet scrubber in which CO_2-generating reagents (such as sodium carbonate or calcium carbonate) are used.
[f]References 13-14.
[g]Reference 13. Based on measurements collected downstream of PM control devices which may have provided some removal of polycyclic organic matter (POM) condensed on PM.

Table 1.8-2 (English Units). EMISSION FACTORS FOR BAGASSE-FIRED BOILERS[a]

Pollutant	Emission factor		Rating
	lb/1,000 lb steam[b]	lb/ton bagasse[c]	
Particulate matter[d]			
Uncontrolled	3.9	15.6	C
Controlled			
Mechanical collector	2.1	8.4	D
Wet scrubber	0.4	1.6	B
PM-10[d]			
Controlled			
Wet scrubber	0.34	1.36	D
Carbon dioxide			
Uncontrolled[e]	390	1,560	A
Nitrogen oxides			
Uncontrolled[f]	0.3	1.2	C
Polycyclic organic matter			
Uncontrolled[g]	2.5E-4	1.0E-3	D

[a]Source Classification Code is 10201101.
[b]Units are lbs. of pollutant/1,000 lbs. of steam produced, where 1 lb. of wet bagasse fired produces 2 lbs. of steam.
[c]Units are lbs. of pollutant/ton of wet, as-fired bagasse containing approximately 50 percent moisture, by weight.
[d]References 2, 6-14. Includes only filterable PM (i.e., that particulate collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
[e]References 6-14. CO_2 emissions will increase following a wet scrubber in which CO_2-generating reagents (such as sodium carbonate or calcium carbonate) are used.
[f]References 13-14.
[g]Reference 13. Based on measurements collected downstream of PM control devices which may have provided some removal of polycyclic organic matter (POM) condensed on PM.

References for Section 1.8

1. *Potential Control Strategies for Bagasse Fired Boilers*, EPA Contract No. 68-02-0627, Engineering-Science, Inc., Arcadia, CA, May 1978.

2. *Background Document: Bagasse Combustion in Sugar Mills*, EPA-450/3-77-077, U. S. Environmental Protection Agency, Research Triangle Park, NC, January 1977.

3. *Nonfossil Fuel Fired Industrial Boilers - Background Information*, EPA-450/3-82-007, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.

4. *A Technology Assessment of Solar Energy Systems: Direct Combustion of Wood and Other Biomass in Industrial Boilers*, ANL/EES-TM--189, Angonne National Laboratory, Argonne, IL, December 1981.

5. *Emission Factor Documentation for AP-42 Section 1.8 - Bagasse Combustion in Sugar Mills*, Technical Support Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1993.

6. *Particulate Emissions Test Report: Atlantic Sugar Association*, Air Quality Consultants, Inc., December 20, 1978.

7. *Compliance Stack Test: Gulf and Western Food Products: Report No. 238-S*, South Florida Environmental Services, Inc., February 1980.

8. *Compliance Stack Test: Gulf and Western Food Products: Report No. 221-S*, South Florida Environmental Services, Inc., January 1980.

9. *Compliance Stack Test: United States Sugar Corporation: Report No. 250-S*, South Florida Environmental Services, Inc., February 1980.

10. *Compliance Stack Test: Osceola Farms Company: Report No. 215-S*, South Florida Environmental Services, Inc., December 1979.

11. *Source Emissions Survey of Davies Hamakua Sugar Company: Report No. 79-34*, Mullins Environmental Testing Company, May 1979.

12. *Source Emissions Survey: Honokaa Sugar Company*, Kennedy Engineers, Inc., January, 19 1979.

13. *Stationary Source Testing of Bagasse Fired Boilers at the Hawaiian Commercial and Sugar Company: Puunene, Maui, Hawaii*, EPA Contract No. 68-02-1403, Midwest Research Institute, Kansas City, MO, February 1976.

14. *Emission Test Report: U. S. Sugar Company, Bryant Florida*, EPA Contract No. 68-02-2818, Monsanto Research Corporation, Dayton, OH, May 1980.

1.9 RESIDENTIAL FIREPLACES

1.9.1 General[1,2]

Fireplaces are used primarily for aesthetic effects and secondarily as a supplemental heating source in houses and other dwellings. Wood is the most common fuel for fireplaces, but coal and densified wood "logs" may also be burned. The user intermittently adds fuel to the fire by hand.

Fireplaces can be divided into two broad categories, 1) masonry (generally brick and/or stone, assembled on site, and integral to a structure) and 2) prefabricated (usually metal, installed on site as a package with appropriate duct work).

Masonry fireplaces typically have large fixed openings to the fire bed and have dampers above the combustion area in the chimney to limit room air and heat losses when the fireplace is not being used. Some masonry fireplaces are designed or retrofitted with doors and louvers to reduce the intake of combustion air during use.

Prefabricated fireplaces are commonly equipped with louvers and glass doors to reduce the intake of combustion air, and some are surrounded by ducts through which floor level air is drawn by natural convection, heated and returned to the room. Many varieties of prefabricated fireplaces are now available on the market. One general class is the freestanding fireplace, the most common of which consists of an inverted sheet metal funnel and stovepipe directly above the fire bed. Another class is the "zero clearance" fireplace, an iron or heavy gauge steel firebox lined inside with firebrick and surrounded by multiple steel walls with spaces for air circulation. Some zero clearance fireplaces can be inserted into existing masonry fireplace openings, and thus are sometimes called "inserts." Some of these units are equipped with close fitting doors and have operating and combustion characteristics similar to wood stoves. (See Section 1.10, Residential Wood Stoves.)

Masonry fireplaces usually heat a room by radiation, with a significant fraction of the combustion heat lost in the exhaust gases and through fireplace walls. Moreover, some of the radiant heat entering the room goes toward warming the air that is pulled into the residence to make up for that drawn up the chimney. The net effect is that masonry fireplaces are usually inefficient heating devices. Indeed, in cases where combustion is poor, where the outside air is cold, or where the fire is allowed to smolder (thus drawing air into a residence without producing appreciable radiant heat energy), a net heat loss may occur in a residence using a fireplace. Fireplace heating efficiency may be improved by a number of measures that either reduce the excess air rate or transfer back into the residence some of the heat that would normally be lost in the exhaust gases or through fireplace walls. As noted above, such measures are commonly incorporated into prefabricated units. As a result, the energy efficiencies of prefabricated fireplaces are slightly higher than those of masonry fireplaces.

1.9.2 Emissions[1-13]

The major pollutants of concern from fireplaces are unburnt combustibles, including carbon monoxide, gaseous organics and particulate matter (i.e., smoke). Significant quantities of unburnt combustibles are produced because fireplaces are inefficient combustion devices, with high uncontrolled excess air rates and without any sort of secondary combustion. The latter is especially important in wood burning because of its high volatile matter content, typically 80 percent by dry

weight. In addition to unburnt combustibles, lesser amounts of nitrogen oxides and sulfur oxides are emitted.

Hazardous Air Pollutants (HAPs) are a minor, but potentially important component of wood smoke. A group of HAPs known as polycyclic organic matter (POM) includes potential carcinogens such as benzo(a)pyrene (BaP). POM results from the combination of free radical species formed in the flame zone, primarily as a consequence of incomplete combustion. Under reducing conditions, radical chain propagation is enhanced, allowing the buildup of complex organic material such as POM. The POM is generally found in or on smoke particles, although some sublimation into the vapor phase is probable.

Another important constituent of wood smoke is creosote. This tar-like substance will burn if the fire is hot enough, but at insufficient temperatures, it may deposit on surfaces in the exhaust system. Creosote deposits are a fire hazard in the flue, but they can be reduced if the chimney is insulated to prevent creosote condensation or if the chimney is cleaned regularly to remove any buildup.

Fireplace emissions are highly variable and are a function of many wood characteristics and operating practices. In general, conditions which promote a fast burn rate and a higher flame intensity enhance secondary combustion and thereby lower emissions. Conversely, higher emissions will result from a slow burn rate and a lower flame intensity. Such generalizations apply particularly to the earlier stages of the burning cycle, when significant quantities of combustible volatile matter are being driven out of the wood. Later in the burning cycle, when all volatile matter has been driven out of the wood, the charcoal that remains burns with relatively few emissions.

Emission factors and their ratings for wood combustion in residential fireplaces are given in Tables 1.9-1. and 1.9-2.

Table 1.9-1. (ENGLISH UNITS) EMISSION FACTORS FOR WOOD COMBUSTION IN RESIDENTIAL FIREPLACES
(Source Classification Code: 2104008001)

Device	Pollutant	Emission Factor[a] lb/ton	Rating
Fireplace	PM-10[b]	34.6	B
	Carbon Monoxide[c]	252.6	B
	Sulfur Oxides[d]	0.4	A
	Nitrogen oxides[e]	2.6	C
	Carbon Dioxide[f]	3400	C
	Total VOCs[g]	229.0	D
	POM[h]	1.6E-3	E[j]
	Aldehydes[k]	2.4	E[j]

[a]Units are in lbs. of pollutant/ton of dry wood burned.
[b]References 2, 5, 7, 13; contains filterable and condensable particulate matter (PM); PM emissions are considered to be 100% PM-10 (i.e., PM with an aerodynamic diameter of 10μm or less).
[c]References 2, 4, 5, 9, 13.
[d]References 1, 8.
[e]References 4, 9; expressed as NO_2.
[f]References 5, 13
[g]References 4 - 5, 8. Data used to calculate the average emission factor were collected by various methods. While the emission factor may be representative of the source population in general, factors may not be accurate for individual sources.
[h]Reference 2.
[j]Data used to calculate the average emission factor were collected from a single fireplace and are not representative of the general source population.
[k]References 4, 11.

Table 1.9-2. (METRIC UNITS) EMISSION FACTORS FOR WOOD COMBUSTION IN RESIDENTIAL FIREPLACES
(Source Classification Code: 2104008001)

Device	Pollutant	Emission Factor[a] g/kg	Rating
Fireplace	PM-10[b]	17.3	B
	Carbon Monoxide[c]	126.3	B
	Sulfur Oxides[d]	0.2	A
	Nitrogen oxides[e]	1.3	C
	Carbon Dioxide[f]	1700	C
	Total VOCs[g]	114.5	D
	POM[h]	0.8E-3	E[j]
	Aldehydes[k]	1.2	E[j]

[a]Units are in grams of pollutant/kg of dry wood burned.
[b]References 2, 5, 7, 13; contains filterable and condensable particulate matter (PM); PM emissions are considered to be 100% PM-10 (i.e., PM with an aerodynamic diameter of 10μm or less).
[c]References 2, 4, 5, 9, 13.
[d]References 1, 8.
[e]References 4, 9; expressed as NO_2.
[f]References 5, 13
[g]References 4 - 5, 8. Data used to calculate the average emission factor were collected by various methods. While the emission factor may be representative of the source population in general, factors may not be accurate for individual sources.
[h]Reference 2.
[j]Data used to calculate the average emission factor were collected from a single fireplace and are not representative of the general source population.
[k]References 4, 11.

References for Section 1.9

1. DeAngelis, D.G., et al., Source Assessment: Residential Combustion Of Wood, EPA-600/2-80-042b, U.S. Environmental Protection Agency, Cincinnati, OH, March 1980.

2. Snowden, W.D., et al., Source Sampling Residential Fireplaces For Emission Factor Development, EPA-450/3-76-010, U.S. Environmental Protection Agency, Research Triangle Park, NC, November 1975.

3. Shelton, J.W., and L. Gay, Colorado Fireplace Report, Colorado Air Pollution Control Division, Denver, CO, March 1987.

4. Dasch, J.M., "Particulate And Gaseous Emissions From Wood-burning Fireplaces," Environmental Science And Technology, 16(10):643-67, October 1982.

5. Source Testing For Fireplaces, Stoves, And Restaurant Grills In Vail, Colorado, EPA Contract No. 68-01-1999, Pedco Environmental, Inc., Cincinnati, OH, December 1977.

6. Written communication from Robert C. McCrillis, U.S. Environmental Protection Agency, Research Triangle Park, NC, to Neil Jacquay, U.S. Environmental Protection Agency, San Francisco, CA, November 19, 1985.

7. Development Of AP-42 Emission Factors For Residential Fireplaces, EPA Contract No. 68-D9-0155, Advanced Systems Technology, Inc., Atlanta, GA, January 11, 1990.

8. DeAngelis, D.G., et al., Preliminary Characterization Of Emissions From Wood Fired Residential Combustion Equipment, EPA-600/7-80-040, U.S. Environmental Protection Agency, Cincinnati, OH, March 1980.

9. Kosel, P., et al., Emissions From Residential Fireplaces, CARB Report C-80-027, California Air Resources Board, Sacramento, CA, April 1980.

10. Clayton, L., et al., Emissions From Residential Type Fireplaces, Source Tests 24C67, 26C, 29C67, 40C67, 41C67, 65C67 and 66C67, Bay Area Air Pollution Control District, San Francisco, CA, January 31, 1968.

11. Lipari, F., et al., Aldehyde Emissions From Wood-Burning Fireplaces, Publication GMR-4377R, General Motors Research Laboratories, Warren, MI, March 1984.

12. Hayden, A., C.S., and R.W. Braaten, "Performance Of Domestic Wood Fired Appliances," Presented at the 73rd Annual Meeting of the Air Pollution Control Association, Montreal, Quebec, Canada, June 1980.

13. Barnett, S.G., In-Home Evaluation of Emissions From Masonry Fireplaces and Heaters, OMNI Environmental Services, Inc., Beaverton, OR, September 1991.

1.10 RESIDENTIAL WOOD STOVES

1.10.1 General[1,2]

Wood stoves are commonly used in residences as space heaters. They are used both as the primary source of residential heat and to supplement conventional heating systems.

Five different categories should be considered when estimating emissions from wood burning devices due to differences in both the magnitude and the composition of the emissions:

- the conventional wood stove,
- the noncatalytic wood stove,
- the catalytic wood stove,
- the pellet stove, and
- the masonry heater.

Among these categories, there are many variations in device design and operation characteristics.

The conventional stove category comprises all stoves without catalytic combustors not included in the other noncatalytic categories (i.e., noncatalytic and pellet). Conventional stoves do not have any emission reduction technology or design features and, in most cases, were manufactured before July 1, 1986. Stoves of many different airflow designs may be in this category, such as updraft, downdraft, crossdraft and S-flow.

Noncatalytic wood stoves are those units that do not employ catalysts but do have emission reducing technology or features. Typical noncatalytic design includes baffles and secondary combustion chambers.

Catalytic stoves are equipped with a ceramic or metal honeycomb device, called a combustor or converter, that is coated with a noble metal such as platinum or palladium. The catalyst material reduces the ignition temperature of the unburned volatile organic compounds (VOC) and carbon monoxide (CO) in the exhaust gases, thus augmenting their ignition and combustion at normal stove operating temperatures. As these components of the gases burn, the temperature inside the catalyst increases to a point at which the ignition of the gases is essentially self sustaining.

Pellet stoves are those fueled with pellets of sawdust, wood products, and other biomass materials pressed into manageable shapes and sizes. These stoves have active air flow systems and unique grate design to accommodate this type of fuel. Some pellet stove models are subject to the 1988 New Source Performance Standards (NSPS), while others are exempt due to a high air-to-fuel ratio (i.e., greater than 35-to-1).

Masonry heaters are large, enclosed chambers made of masonry products or a combination of masonry products and ceramic materials. These devices are exempt from the 1988 NSPS due to their weight (i.e., greater than 800 kg). Masonry heaters are gaining popularity as a cleaner burning and

heat efficient form of primary and supplemental heat, relative to some other types of wood heaters. In a masonry heater, a complete charge of wood is burned in a relatively short period of time. The use of masonry materials promotes heat transfer. Thus, radiant heat from the heater warms the surrounding area for many hours after the fire has burned out.

1.10.2 Emissions

The combustion and pyrolysis of wood in wood stoves produce atmospheric emissions of particulate matter, carbon monoxide, nitrogen oxides, organic compounds, mineral residues, and to a lesser extent, sulfur oxides. The quantities and types of emissions are highly variable, depending on a number of factors, including stage of the combustion cycle. During initial burning stages, after a new wood charge is introduced, emissions (primarily VOCs) increase dramatically. After the initial period of high burn rate, there is a charcoal stage of the burn cycle characterized by a slower burn rate and decreased emissions. Emission rates during this stage are cyclical, characterized by relatively long periods of low emissions and shorter episodes of emission spikes.

Particulate emissions are defined in this discussion as the total catch measured by the EPA Method 5H (Oregon Method 7) sampling train.[1] A small portion of wood stove particulate emissions includes "solid" particles of elemental carbon and wood. The vast majority of particulate emissions is condensed organic products of incomplete combustion equal to or less than 10 micrometers in aerodynamic diameter (PM-10). Although reported particle size data are scarce, one reference states that 95 percent of the particles emitted from a wood stove were less than 0.4 micrometers in size.[3]

Sulfur oxides (SO_x) are formed by oxidation of sulfur in the wood. Nitrogen oxides (NO_x) are formed by oxidation of fuel and atmospheric nitrogen. Mineral constituents, such as potassium and sodium compounds, are released from the wood matrix during combustion.

The high levels of organic compound and CO emissions are results of incomplete combustion of the wood. Organic constituents of wood smoke vary considerably in both type and volatility. These constituents include simple hydrocarbons of carbon numbers 1 through 7 (C1 - C7) (which exist as gases or which volatilize at ambient conditions) and complex low volatility substances that condense at ambient conditions. These low volatility condensible materials generally are considered to have boiling points below 300°C (572°F).

Polycyclic organic matter (POM) is an important component of the condensible fraction of wood smoke. POM contains a wide range of compounds, including organic compounds formed through incomplete combustion by the combination of free radical species in the flame zone. This group which is classified as a Hazardous Air Pollutant (HAP) under Title III of the 1990 Clean Air Act Amendments contains the sub-group of hydrocarbons called Polycyclic Aromatic Hydrocarbons (PAH).

Emission factors and their ratings for wood combustion in residential wood stoves, pellet stoves and masonry heaters are presented in Tables 1.10-1 through 1.10-8. The analysis leading to the revision of these emission factors is contained in the emission factor documentation.[29] These tables include emission factors for criteria pollutants (PM-10, CO, NO_x, SO_x), CO_2, Total Organic Compounds (TOC), speciated organic compounds, PAH, and some elements. The emission factors are presented by wood heater type. PM-10 and CO emission factors are further classified by stove certification category. Phase II stoves are those certified to meet the July 1, 1990 EPA standards;

Phase I stoves meet only the July 1, 1988 EPA standards; and Pre-Phase I stoves do not meet any of the EPA standards but in most cases do necessarily meet the Oregon 1986 certification standards.[1] The emission factors for PM and CO in Tables 1.10-1 and 1.10-2 are averages, derived entirely from field test data obtained under actual operating conditions. Still, there is a potential for higher emissions from some wood stove, pellet stove and masonry heater models.

As mentioned, particulate emissions are defined as the total emissions equivalent to that collected by EPA Method 5H. This method employs a heated filter followed by three impingers, an unheated filter, and a final impinger. Particulate emissions factors are presented as values equivalent to that collected with Method 5H. Conversions are employed, as appropriate, for data collected with other methods.

Table 1.10-7 shows net efficiency by device type, determined entirely from field test data. Net or overall efficiency is the product of combustion efficiency multiplied by heat transfer efficiency. Wood heater efficiency is an important parameter used, along with emission factors and percent degradation, when calculating PM-10 emission reduction credits. Percent degradation is related to the loss in effectiveness of a wood stove control device or catalyst over a period of operation. Control degradation for any stove, including noncatalytic wood stoves, may also occur as a result of deteriorated seals and gaskets, misaligned baffles and bypass mechanisms, broken refractories, or other damaged functional components. The increase in emissions which can result from control degradation has not been quantified. However, recent wood stove testing in Colorado and Oregon should produce results which allow estimation of emissions as a function of stove age.

TABLE 1.10-1. (ENGLISH UNITS) EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a]
(Source Classification Codes)

Pollutant/EPA Certification[b]	Emission Factor Rating	Wood Stove Type			Pellet Stove Type[c] (SCC 2104008053)		Masonry Heater (SCC 2104008055)
		Conventional (SCC 2104008051)	Noncatalytic (SCC 2104008050)	Catalytic (SCC 2104008030)	Certified	Exempt	Exempt[d]
PM-10[e]							
Pre-Phase I	B	30.6	25.8	24.2			
Phase I	B		20.0	19.6			
Phase II	B		14.6	16.2	4.2		
All	B	30.6	19.6	20.4	4.2	8.8	5.6
Carbon Monoxide[e]							
Pre-Phase I	B	230.8					
Phase I	B			104.4			
Phase II	B		140.8	107.0	39.4		
All	B	230.8	140.8	104.4	39.4	52.2	149.0
Nitrogen Oxides[e]		2.8[f]		2.0[g]	13.8[g]		
Sulfur Oxides[e]	B	0.4	0.4	0.4	0.4		
Carbon Dioxide[h]	C				2,951.6	3,671.2	3,849.4
TOC[j]	E	48.6		24.2			
Methane	E	4.8		8.6			
TNMOC	E	43.8		15.6			

[a]Units are in lbs. of pollutant/ton of dry wood burned.
[b]Pre-Phase I = Not certified to 1988 EPA emission standards; Phase I = Certified to 1988 EPA emission standards; Phase II = Certified to 1990 EPA emission standards; All = Average of emission factors for all devices.
[c]Certified = Certified pursuant to 1988 NSPS; Exempt = Exempt from 1988 NSPS (i.e., air : ratio >35:1).
[d]Exempt = Exempt from 1988 NSPS (i.e., device weight >800 kg).
[e]References 6 - 14, 23 - 27, 29. PM-10 is defined as equivalent to total catch by EPA method 5H train.
[f]Rating = C.
[g]Rating = E.
[h]References 13, 24 - 27, 29.
[j]References 13, 17 - 18. TOC = Total organic compounds; TNMOC = Total nonmethane organic compounds. Data show a high degree of variability within the source population. Factors may not be accurate for individual sources.

TABLE 1.10-2. (METRIC UNITS) EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a]
(Source Classification Codes)

Pollutant/EPA Certification[b]	Emission Factor Rating	Wood Stove Type			Pellet Stove Type[c] (SCC 2104008053)		Masonry Heater (SCC 2104008055)
		Conventional (SCC 2104008051)	Noncatalytic (SCC 2104008050)	Catalytic (SCC 2104008030)	Certified	Exempt	Exempt[d]
PM-10[e]							
Pre-Phase I	B	15.3	12.9	12.1			
Phase I	B		10.0	9.8			
Phase II	B		7.3	8.1	2.1		
All	B	15.3	9.8	10.2	2.1	4.4	2.8
Carbon Monoxide[e]							
Pre-Phase I	B	115.4					
Phase I	B			52.2			
Phase II	B		70.4		19.7		
All	B	115.4	70.4	52.2	19.7	26.1	74.5
Nitrogen Oxides[e]		1.4[f]		1.0[g]	6.9[g]		
Sulfur Oxides[e]	B	0.2	0.2	0.2	0.2		
Carbon Dioxide[h]	C				1,475.8	1,835.6	1,924.7
TOC[j]	E	24.3		12.1			
Methane	E	2.4		4.3			
TNMOC	E	21.9		7.8			

[a]Units are in grams of pollutant/kg of dry wood burned.
[b]Pre-Phase I = Not certified to 1988 EPA emission standards; Phase I = Certified to 1988 EPA emission standards; Phase II = Certified to 1990 EPA emission standards; All = Average of emission factors for all devices.
[c]Certified = Certified pursuant to 1988 NSPS; Exempt = Exempt from 1988 NSPS (i.e., air : fuel >35:1).
[d]Exempt = Exempt from 1988 NSPS (i.e., device weight >800 kg).
[e]References 6 - 14, 23 - 27, 29. PM-10 is defined as equivalent to total catch by EPA method 5H train.
[f]Rating = C.
[g]Rating = E.
[h]References 13, 24 - 27, 29.
[j]References 13, 17 - 18. TOC = Total organic compounds; TNMOC = Total nonmethane organic compounds. Data show a high degree of variability within the source population. Factors may not be accurate for individual sources.

TABLE 1.10-3. (ENGLISH AND METRIC UNITS) ORGANIC COMPOUND EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a]
(Source Classification Codes)

(EMISSION FACTOR RATING: E)[b]

Compounds	WOOD STOVE TYPE			
	Conventional (SCC 2104008051)		Catalytic (SCC 2104008030)	
	lb/ton	g/kg	lb/ton	g/kg
Ethane	1.470	0.735	1.376	0.688
Ethylene	4.490	2.245	3.482	1.741
Acetylene	1.124	0.562	0.564	0.282
Propane	0.358	0.179	0.158	0.079
Propene	1.244	0.622	0.734	0.367
i-Butane	0.028	0.014	0.010	0.005
n-Butane	0.056	0.028	0.014	0.007
Butenes[c]	1.192	0.596	0.714	0.357
Pentenes[d]	0.616	0.308	0.150	0.075
Benzene	1.938	0.969	1.464	0.732
Toluene	0.730	0.365	0.520	0.260
Furan	0.342	0.171	0.124	0.062
Methyl Ethyl Ketone	0.290	0.145	0.062	0.031
2-Methyl Furan	0.656	0.328	0.084	0.042
2,5-Dimethyl Furan	0.162	0.081	0.002	0.011
Furfural	0.486	0.243	0.146	0.073
O-Xylene	0.202	0.101	0.186	0.093

[a]Reference 17. Units are in lbs. of pollutant/ton of dry wood burned and grams of pollutant/kg of dry wood burned.
[b]Data show a high degree of variability within the source population. Factors may not be accurate for individual sources.
[c]1-butene, i-butene, t-2-butene, c-2-butene, 2-me-1-butene, 2-me-butene are reported as butenes.
[d]1-pentene, t-2-pentene, and c-2-pentene are reported as pentenes.

TABLE 1.10-4. (ENGLISH UNITS) POLYCYCLIC AROMATIC HYDROCARBON (PAH) EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a]
(Source Classification Codes)

(EMISSION FACTOR RATING: E)[b]

Pollutant	STOVE TYPE			
	Conventional[c] (SCC 2104008051)	Noncatalytic[d] (SCC 2104008050)	Catalytic[e] (SCC 2104008030)	Exempt Pellet[f] (SCC 2104008053)
PAH				
Acenaphthene	0.010	0.010	0.006	
Acenaphthylene	0.212	0.032	0.068	
Anthracene	0.014	0.009	0.008	
Benzo(a)Anthracene	0.020	<0.001	0.024	
Benzo(b)Fluoranthene	0.006	0.004	0.004	2.60E-05
Benzo(g,h,i)Fluoranthene		0.028	0.006	
Benzo(k)Fluoranthene	0.002	<0.001	0.002	
Benzo(g,h,i)Perylene	0.004	0.020	0.002	
Benzo(a)Pyrene	0.004	0.006	0.004	
Benzo(e)Pyrene	0.012	0.002	0.004	
Biphenyl		0.022		
Chrysene	0.012	0.010	0.010	7.52E-05
Dibenzo(a,h)Anthracene	0.000	0.004	0.002	
7,12-Dimethylbenz(a)Anthracene		0.004		
Fluoranthene	0.020	0.008	0.012	5.48E-05
Fluorene	0.024	0.014	0.014	
Indeno(1,2,3,cd)Pyrene	0.000	0.020	0.004	
9-Methylanthracene		0.004		
12-Methylbenz(a)Anthracene		0.002		
3-Methylchlolanthrene		<0.001		
1-Methylphenanthrene		0.030		
Naphthalene	0.288	0.144	0.186	
Nitronaphthalene		0.000		
Perylene		0.002		
Phenanthrene	0.078	0.118	0.489	3.32E-05
Phenanthrol		0.000		
Phenol		<0.001		
Pyrene	0.024	0.008	0.010	4.84E-05
PAH Total	0.730	0.500	0.414	

[a]Units are in lbs. of pollutant/ton of dry wood burned.
[b]Data show a high degree of variability within the source population and/or came from a small number of sources. Factors may not be accurate for individual sources.
[c]Reference 17.
[d]References 15, 18 - 20.
[e]References 14 - 18.
[f]Reference 27. Exempt = Exempt from 1988 NSPS (i.e., air : fuel >35:1).

TABLE 1.10-5. (METRIC UNITS) POLYCYCLIC AROMATIC HYDROCARBON (PAH) EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a]
(Source Classification Codes)

(Emission Factor Rating: E)[b]

Pollutant	STOVE TYPE			
	Conventional[c] (SCC 2104008051)	Noncatalytic[d] (SCC 2104008050)	Catalytic[e] (SCC 2104008030)	Exempt Pellet[f] (SCC 2104008053)
PAH				
Acenaphthene	0.005	0.005	0.003	
Acenaphthylene	0.106	0.016	0.034	
Anthracene	0.007	0.004	0.004	
Benzo(a)Anthracene	0.010	<0.001	0.012	
Benzo(b)Fluoranthene	0.003	0.002	0.002	1.30E-05
Benzo(g,h,i)Fluoranthene		0.014	0.003	
Benzo(k)Fluoranthene	0.001	<0.001	0.001	
Benzo(g,h,i)Perylene	0.002	0.010	0.001	
Benzo(a)Pyrene	0.002	0.003	0.002	
Benzo(e)Pyrene	0.006	0.001	0.002	
Biphenyl		0.011		
Chrysene	0.006	0.005	0.005	3.76E-05
Dibenzo(a,h)Anthracene	0.000	0.002	0.001	
7,12-Dimethylbenz(a)Anthracene		0.002		
Fluoranthene	0.010	0.004	0.006	2.74E-05
Fluorene	0.012	0.007	0.007	
Indeno(1,2,3,cd)Pyrene	0.000	0.010	0.002	
9-Methylanthracene		0.002		
12-Methylbenz(a)Anthracene		0.001		
3-Methylchlolanthrene		<0.001		
1-Methylphenanthrene		0.015		
Naphthalene	0.144	0.072	0.093	
Nitronaphthalene		0.000		
Perylene		0.001		
Phenanthrene	0.039	0.059	0.024	1.66E-05
Phenanthrol		0.000		
Phenol		<0.001		
Pyrene	0.012	0.004	0.005	2.42E-05
PAH Total	0.365	0.250	0.207	

[a]Units are in grams of pollutant/kg of dry wood burned.
[b]Data show a high degree of variability within the source population and/or came from a small number of sources. Factors may not be accurate for individual sources.
[c]Reference 17.
[d]References 15, 18 - 20.
[e]References 14 - 18.
[f]Reference 27. Exempt = Exempt from 1988 NSPS (i.e., air : fuel >35:1).

TABLE 1.10-6. (ENGLISH AND METRIC UNITS) TRACE ELEMENT EMISSION FACTORS FOR RESIDENTIAL WOOD COMBUSTION[a]
(Source Classification Codes)

(EMISSION FACTOR RATING: E)[b]

Element	WOOD STOVE TYPE					
	Conventional (SCC 2104008051)		Noncatalytic (SCC 2104008050)		Catalytic (SCC 2104008030)	
	lb/ton	g/kg	lb/ton	g/kg	lb/ton	g/kg
Cadmium (Cd)	2.2E-05	1.1E-05	2.0E-05	1.0E-05	4.6E-05	2.3E-05
Chromium (Cr)	<1.0E-06	<1.0E-06	<1.0E-06	<1.0E-05	<1.0E-06	<1.0-E06
Manganese (Mn)	1.7E-04	8.7E-05	1.4E-04	7.0E-05	2.2E-04	1.1E-04
Nickel (Ni)	1.4E-05	7.0E-06	2.0E-05	1.0E-05	2.2E-06	1.0E-06

[a]References 14, 17. Units are in lbs. of pollutant/ton of dry wood burned and grams of pollutant/kg of dry wood burned.
[b]The data used to develop these emission factors showed a high degree of variability within the source population. Factors may not be accurate for individual sources.

TABLE 1.10-7. SUMMARY OF WOOD HEATER NET EFFICIENCIES[a]

Wood Heater Type	Source Classification Code	Net Efficiency (%)	Reference
Wood Stoves			
Conventional	2104008051	54	26
Noncatalytic	2104008050	68	9, 12, 26
Catalytic	2104008030	68	6, 26
Pellet Stoves[b]			
Certified	2104008053	68	11
Exempt		56	27
Masonry Heaters			
All	2104008055	58	28

[a]Net efficiency is a function of both combustion efficiency and heat transfer efficiency. The percentages shown here are based on data collected from in-home testing.
[b]Certified = Certified pursuant to 1988 NSPS.
Exempt = Exempt from 1988 NSPS (i.e., air : fuel >35:1).

REFERENCES FOR SECTION 1.10

1. Standards Of Performance For New Stationary Sources: New Residential Wood Heaters, 53 FR 5573, February 26, 1988.

2. Gay, R., and J. Shah, Technical Support Document For Residential Wood Combustion, EPA-450/4-85-012, U.S. Environmental Protection Agency, Research Triangle Park, NC, February 1986.

3. Rau, J.A., and J.J. Huntzicker, Composition And Size Distribution Of Residential Wood Smoke Aerosols, Presented at the 21st Annual Meeting of the Air and Waste Management Association, Pacific Northwest International Section, Portland, OR, November 1984.

4. Simons, C.A., et al., Whitehorse Efficient Woodheat Demonstration, The City of Whitehorse, Whitehorse, Yukon, Canada, September 1987.

5. Simons, C.A., et al., Woodstove Emission Sampling Methods Comparability Analysis And In-situ Evaluation Of New Technology Woodstoves, EPA-600/7-89-002, U.S. Environmental Protection Agency, Cincinnati, OH, January 1989.

6. Barnett, S.G., Field Performance Of Advanced Technology Woodstoves In Glens Falls, N.Y. 1988-1989., Vol. 1, New York State Energy Research and Development Authority, Albany, NY, October 1989.

7. Burnet, P.G., The Northeast Cooperative Woodstove Study, Volume 1, EPA-600/7-87-026a, U.S. Environmental Protection Agency, Cincinnati, OH, November 1987.

8. Jaasma, D.R., and M.R. Champion, Field Performance Of Woodburning Stoves In Crested Butte During The 1989-90 Heating Season, Town of Crested Butte, Crested Butte, CO, September 1990.

9. Dernbach, S., Woodstove Field Performance In Klamath Falls, OR, Wood Heating Alliance, Washington, DC, April 1990.

10. Simons, C.A., and S.K. Jones, Performance Evaluation Of The Best Existing Stove Technology (BEST) Hybrid Woodstove And Catalytic Retrofit Device, Oregon Department of Environmental Quality, Portland, OR, July 1989.

11. Barnett, S.G., and R.B. Roholt, In-home Performance Of Certified Pellet Stoves In Medford And Klamath Falls, OR, U.S. Department of Energy Report No. PS407-02, July 1990.

12. Barnett, S.G., In-Home Evaluation of Emission Characteristics of EPA-Certified High-Tech Non-Catalytic Woodstoves in Klamath Falls, OR, 1990, prepared for the Canada Center for Mineral and Energy Technology, Energy, Mines and Resources, Canada, DSS File No. 145Q, 23440-9-9230, June 1, 1990.

13. McCrillis, R.C., and R.G. Merrill, Emission Control Effectiveness Of A Woodstove Catalyst And Emission Measurement Methods Comparison, Presented at the 78th Annual Meeting of the Air And Waste Management Association, Detroit, MI, 1985.

14. Leese, K.E., and S.M. Harkins, Effects Of Burn Rate, Wood Species, Moisture Content And Weight Of Wood Loaded On Woodstove Emissions, EPA 600/2-89-025, U.S. Environmental Protection Agency, Cincinnati, OH, May 1989.

15. Allen, J.M., and W.M. Cooke, Control Of Emissions From Residential Wood Burning By Combustion Modification, EPA-600/7-81-091, U.S. Environmental Protection Agency, Cincinnati, OH, May 1981.

16. DeAngelis, D.G., et al., Preliminary Characterization Of Emissions From Wood-fired Residential Combustion Equipment, EPA-600/7-80-040, U.S. Environmental Protection Agency, Cincinnati, OH, March 1980.

17. Burnet, P.G., et al., Effects of Appliance Type and Operating Variables on Woodstove Emissions, Vol. I., Report and Appendices 6-C, EPA-600/2-90-001a, U.S. Environmental Protection Agency, Research Triangle Park, NC, January 1990.

18. Cottone, L.E., and E. Mesner, Test Method Evaluations and Emissions Testing for Rating Wood Stoves, EPA-600/2-86-100, U.S. Environmental Protection Agency, Research Triangle Park, NC, October 1986.

19. Residential Wood Heater Test Report, Phase II Testing, Vol. 1, TVA, Division of Energy, Construction and Rates, Chattanooga, TN, August 1983.

20. Truesdale, R.S. and J.G. Cleland, Residential Stove Emissions from Coal and Other Alternative Fuels Combustion, in papers at the Specialty Conference on Residential Wood and Coal Combustion, Louisville, KY, March 1982.

21. Barnett, S.G., In-Home Evaluation of Emissions From Masonry Fireplaces and Heaters, OMNI Environmental Services, Inc., Beaverton, OR, September 1991.

22. Barnett, S.G., In-Home Evaluation of Emissions From a Grundofen Masonry Heater, OMNI Environmental Services, Inc., Beaverton, OR, January 1992.

23. Barnett, S.G., In-Home Evaluation of Emissions From a Tulikivi KTU 2100 Masonry Heater, OMNI Environmental Services, Inc., Beaverton, OR, March 1992.

24. Barnett, S.G., In-Home Evaluation of Emissions From a Royal Crown 2000 Masonry Heater, OMNI Environmental Services, Inc., Beaverton, OR, March 1992.

25. Barnett, S.G., In-Home Evaluation of Emissions From a Biofire 4x3 Masonry Heater, OMNI Environmental Services, Inc., Beaverton, OR, March 1992.

26. Barnett, S.G. and R.D. Bighouse, In-Home Demonstrations of the Reduction of Woodstove Emissions from the use of Densified Logs, Oregon Department of Energy and U.S. Environmental Protection Agency, July 1992.

27. Barnett, S.G. and P.G. Fields, In-Home Performance of Exempt Pellet Stoves in Medford, Oregon, U. S. Department of Energy, Oregon Department of Energy, Tennessee Valley Authority, and Oregon Department of Environmental Quality, July 1991.

28. Barnett, S.G., Summary Report of the In-Home Emissions and Efficiency Performance of Five Commercially Available Masonry Heaters, the Masonry Heater Association, May 1992.

29. Emission Factor Documentation for AP-42 Section 1.10, Residential Wood Stoves, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, April 1993.

1.11 WASTE OIL COMBUSTION

1.11.1 General[1]

Waste, or used oil can be burned in a variety of combustion systems including industrial boilers; commercial/institutional boilers; space heaters; asphalt plants; cement and lime kilns; other types of dryers and calciners; and steel production blast furnaces. Boilers and space heaters consume the bulk of the waste oil burned. Space heaters are small combustion units [generally less than 0.1 MW (250,000 Btu/hr input)] that are common in automobile service stations and automotive repair shops where supplies of waste crankcase oil are available.

Boilers designed to burn No. 6 (residual) fuel oils or one of the distillate fuel oils can be used to burn waste oil, with or without modifications for optimizing combustion. As an alternative to boiler modification, the properties of waste oil can be modified by blending it with fuel oil, to the extent required to achieve a clean-burning fuel mixture.

1.11.2 Emissions and Controls[1-3]

Waste oil includes used crankcase oils from automobiles and trucks, used industrial lubricating oils (such as metal working oils), and other used industrial oils (such as heat transfer fluids). When discarded, these oils become waste oils due to a breakdown of physical properties and to contamination by the materials they come in contact with. The different types of waste oils may be burned as mixtures or as single fuels where supplies allow; for example, some space heaters in automotive service stations burn waste crankcase oils.

Contamination of the virgin oils with a variety of materials leads to an air pollution potential when these oils are burned. Potential pollutants include particulate matter (PM), small particles below 10 micrometers in size (PM-10), toxic metals, organic compounds, carbon monoxide (CO), sulfur oxides (SO_x), nitrogen oxides (NO_x), hydrogen chloride, and global warming gases (CO_2, methane).

Ash levels in waste oils are normally much higher than ash levels in either distillate oils or residual oils. Waste oils have substantially higher concentrations of most of the trace elements reported relative to those concentrations found in virgin fuel oils. However, because of the shift to unleaded gasoline, the concentration of lead in waste crankcase oils has continued to decrease in recent years. Without air pollution controls, higher concentrations of ash and trace metals in the waste fuel translate to higher emission levels of PM and trace metals than is the case for virgin fuel oils.

Low efficiency pretreatment steps, such as large particle removal with screens or coarse filters, are common prefeed procedures at oil-fired boilers. Reductions in total PM emissions can be expected from these techniques but little or no effects have been noticed on the levels of (PM-10) emissions.

Constituent chlorine in waste oils typically exceeds the concentration of chlorine in virgin distillate and residual oils. High levels of halogenated solvents are often found in waste oil as a result of inadvertent or deliberate additions of the contaminant solvents to the waste oils. Many efficient combustors can destroy more than 99.99 percent of the chlorinated solvents present in the fuel. However, given the wide array of combustor types which burn waste oils, the presence of these compounds in the emission stream cannot be ruled out.

The flue gases from waste oil combustion often contain organic compounds other than chlorinated solvents. At ppmw levels, several hazardous organic compounds have been found in waste oils. Benzene, toluene, polychlorinated biphenyls (PCBs) and polychlorinated dibenzo-d-dioxins are a few of the hazardous compounds that have been detected in waste oil samples. Additionally, these hazardous compounds may be formed in the combustion process as products of incomplete combustion.

Emission factors and emission factor ratings for waste oil combustion are shown in Tables 1.11-1 through 1.11-5. Emission factors have been determined for emissions from uncontrolled small boilers and space heaters combusting waste oil. The use of both blended and unblended fuels is included in the mix of combustion operations.

Emissions from waste oil used in batch asphalt plants may be estimated using the procedures outlined in Section 4.5.

Table 1.11-1. EMISSION FACTORS FOR PARTICULATE MATTER (PM), PARTICULATE MATTER LESS THAN 10 MICRONS (PM-10), AND LEAD FROM WASTE OIL COMBUSTORS

Source Category (SCC)[a]	PM			PM-10			Lead		
	kg/m^3[d]	lb/1000 gal[e]	Rating	kg/m^3	lb/1000 gal	Rating	kg/m^3	lb/1000 gal	Rating
Small boilers[b] (10301302)	7.3A	61A[f]	C	6.1A	51A	C	6.6L[g]	55L	D
Space heaters[c]									
Vaporizing burner (10500114, 10500214)	0.3A	2.8A	D	ND	ND		0.049L	0.41L	D
Atomizing burner (10500113, 10500213)	7.7A	64A	D	6.8A	57A	E	6.0L	50L	D

[a]SCC = Source Classification Code.
[b]Reference 2, 4-6.
[c]References 6-7.
[d]Units are kg of pollutant/cubic meter of waste oil burned.
[e]Units are lb of pollutant/1000 gallons of waste oil burned.
[f]A = weight percent ash in fuel. Multiply numeric value by A to obtain emission factor.
[g]L = weight percent lead in fuel. Multiply numeric value by L to obtain emission factor.

Table 1.11-2. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x), SULFUR OXIDES (SO_x), AND CARBON MONOXIDE (CO) FROM WASTE OIL COMBUSTORS

Source Category (SCC)[a]	NO_x			SO_x			CO		
	kg/m^3[d]	lb/1000 gal[e]	Rating	kg/m^3	lb/1000 gal	Rating	kg/m^3	lb/1000 gal	Rating
Small boilers[b] (10301302)	19	2.3	C	147S	17.6S[f]	C	5	0.60	D
Space heaters[c]									
Vaporizing burner (10500114, 10500214)	11	1.3	D	100S	12.0S	D	1.7	0.20	D
Atomizing burner (10500113, 10500213)	16	1.9	D	107S	12.8S	D	2.1	0.25	D

[a]SCC = Source Classification Code.
[b]References 2,4,6,8.
[c]References 6-7.
[d]Units are kg of pollutant/cubic meter of waste oil burned.
[e]Units are lb of pollutant/1000 gallons of waste oil burned.
[f]S = weight percent sulfur in fuel. Multiply numeric value by S to obtain emission factor.

Table 1.11-3. EMISSION FACTORS FOR TOTAL ORGANIC COMPOUNDS (TOC), HYDROGEN CHLORIDE (HCl), AND CARBON DIOXIDE (CO_2) FROM WASTE OIL COMBUSTORS

Source Category (SCC)[a]	TOC			HCl			CO_2		
	kg/m^3[d]	lb/1000 gal[e]	Rating	kg/m^3	lb/1000 gal	Rating	kg/m^3	lb/1000 gal	Rating
Small boilers[b] (10301302)	0.01	0.1	D	7.9Cl[f]	66Cl	C	2,400	20,000	C
Space heaters[c]									
Vaporizing burner (10500114, 10500214)	0.01	0.1	D	ND[g]	ND		2,700	23,000	D
Atomizing burner (10500113, 10500213)	0.01	0.1	D	ND	ND		2,900	24,000	D

[a]SCC = Source Classification Code.
[b]References 2,4,6-7,9.
[c]References 4,6-7,9.
[d]Units are kg of pollutant/cubic meter of waste oil burned.
[e]Units are lb of pollutant/1000 gallons of waste oil burned.
[f]Cl = weight percent chlorine in fuel. Multiply numeric value by Cl to obtain emission factor.
[g]ND = No data.

Table 1.11-4 EMISSION FACTORS FOR SPECIATED METALS FROM WASTE OIL COMBUSTORS[a]

EMISSION FACTOR RATING: D

Pollutant	Small Boilers[b] (SCC 10301302)		Space Heaters: Vaporizing Burner[c] (SCC 10500114, 10500214)		Space Heaters: Atomizing Burner[d] (SCC 10500113, 10500213)	
	kg/m^3[e]	lb/1000 gal[f]	kg/m^3	lb/1000 gal	kg/m^3	lb/1000 gal
Antimony	ND	ND	4.1E-05	3.4E-04	5.4E-04	4.5E-03
Arsenic	1.3E-02	1.1E-01	1.3E-04	1.1E-03	7.2E-03	6.0E-02
Beryllium	ND[g]	ND	ND	ND	4.7E-05	3.9E-07
Cadmium	1.1E-03	9.3E-03	1.8E-05	1.5E-04	1.4E-03	1.2E-02
Chromium	2.4E-03	2.0E-02	3.1E-02	2.6E-01	2.2E-02	1.8E-01
Cobalt	2.5E-05	2.1E-04	6.8E-04	5.7E-03	6.2E-04	5.2E-03
Manganese	8.2E-03	6.8E-02	2.6E-04	2.2E-03	6.0E-03	5.0E-02
Nickel	1.3E-03	1.1E-02	6.0E-03	5.0E-02	1.9E-02	1.6E-01
Selenium	ND	ND	ND	ND	ND	ND
Phosphorous	ND	ND	4.3E-03	3.6E-02	ND	ND

[a]Pollutants in this table represent metal species measured for waste oil combustors. Other metal species may also have been emitted but were either not measured or were present at concentrations below analytical detection limits.
[b]Reference 6. SCC = Source Classificatin Code.
[c]References 6-7.
[d]References 6-7.
[e]Units are kg of pollutant/cubic meter of waste oil burned.
[f]Units are lb of pollutant/1000 gallons of waste oil burned.
[g]ND = No data.

Table 1.11-5. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM WASTE OIL COMBUSTORS[a]

EMISSION FACTOR RATING: D

Pollutant	Space Heaters: Vaporizing Burner (SCC 10500114, 10500214)		Space Heaters: Atomizing Burner (SCC 10500113, 10500213)	
	kg/m^3[b]	lb/1000 gal[c]	kg/m^3	lb/1000 gal
Phenol	2.9E-04	2.4E-03	3.3E-06	2.8E-05
Dichlorobenzene	8.0E-07	6.7E-06	ND	ND
Naphthalene	1.6E-03	1.3E-02	1.1E-04	9.4E-04
Phenanthrene/anthracene	1.3E-03	1.1E-02	1.5E-05	9.9E-05
Dibutylphthalate	ND[d]	ND	4.0E-06	3.4E-05
Butylbenzylphthalate	6.1E-05	5.1E-04	ND	ND
Bis(2-ethylhexyl)phthalate	2.6E-04	2.2E-03	ND	ND
Pyrene	8.4E-04	7.0E-03	6.1E-06	5.1E-05
Benz(a)anthracene/chrysene	4.8E-04	4.0E-03	ND	ND
Benzo(a)pyrene	4.8E-04	4.0E-03	ND	ND
Trichloroethylene	ND	ND	ND	ND

[a]Reference 6. Pollutants in this table represent organic species measured for waste oil combustors. Other organic species may also have been emitted but were either not measured or were present at concentrations below analytical detection limits. SCC = Source Classification Code.
[b]Units are kg of pollutant/cubic meter of waste oil burned.
[c]Units are lb of pollutant/1000 gallons of waste oil burned.
[d]ND = No data.

REFERENCES FOR SECTION 1.11

1. *Emission Factor Documentation for AP-42 Section 1.11, Waste Oil Combustion (Draft)*, Technical Support Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1993.

2. *Environmental Characterization of Disposal of Waste Oils in Small Combustors*, EPA-600/2-84-150, U.S. Environmental Protection Agency, Cincinnati, OH, September 1984.

3. "Waste Oil Combustion at a Batch Asphalt Plant: Trial Burn Sampling and Analysis", Arthur D. Little, Inc, Cambridge, MA, Presented at the 76th Annual Meeting of the Air Pollution Control Association, June 1983.

4. *Used Oil Burned as a Fuel*, EPA-SW-892, U. S. Environmental Protection Agency, Washington, DC, August 1980.

5. "Waste Oil Combustion: an Environmental Case Study", Presented at the 75th Annual Meeting of the Air Pollution Control Association, June 1982.

6. *The Fate of Hazardous and Nonhazardous Wastes in Used Oil Disposal and Recycling*, DOE/BC/10375-6, U. S. Department of Energy, Bartlesville, OK, October 1983.

7. "Comparisons of Air Pollutant Emissions from Vaporizing and Air Atomizing Waste Oil Heaters", Journal of the Air Pollution Control Association, 33(7), July 1983.

8. *Chemical Analysis of Waste Crankcase Oil Combustion Samples*, EPA600/7-83-026, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1983.

9. R.L. Barbour and W.M. Cooke, *Chemical Analysis of Waste Crankcase Oil Combustion Samples*, EPA-600/7-83-026, U.S. Environmental Protection Agency, Cincinnati, OH, April 1983.

2.1 REFUSE COMBUSTION

Refuse combustion involves the burning of garbage and other nonhazardous solids, commonly called municipal solid waste (MSW). Types of combustion devices used to burn refuse include single chamber units, multiple chamber units, and trench incinerators.

2.1.1 General[1-3]

As of January 1992, there were over 160 municipal waste combustor (MWC) plants operating in the United States with capacities greater than 36 megagrams per day (Mg/day) [40 tons per day (tpd)], with a total capacity of approximately 100,000 Mg/day (110,000 tpd of MSW).[1] It is projected that by 1997, the total MWC capacity will approach 150,000 Mg/day (165,000 tpd), which represents approximately 28 percent of the estimated total amount of MSW generated in the United States by the year 2000.

Federal regulations for MWCs are currently under three subparts of 40 CFR Part 60. Subpart E covers MWC units that began construction after 1971 and have capacities to combust over 45 Mg/day (50 tpd) of MSW. Subpart Ea establishes new source performance standards (NSPS) for MWC units which began construction or modification after December 20, 1989 and have capacities over 225 Mg/day (250 tpd). An emission guideline (EG) was established under Subpart Ca covering MWC units which began construction or modification prior to December 20, 1989 and have capacities of greater than 225 Mg/day (250 tpd). The Subpart Ea and Ca regulations were promulgated on February 11, 1991.

Subpart E includes a standard for particulate matter (PM). Subpart Ca and Ea currently establish standards for PM, tetra- through octa- chlorinated dibenzo-p-dioxin/chlorinated dibenzofurans (CDD/CDFs), hydrogen chloride (HCl), sulfur dioxide (SO_2), nitrogen oxides (NO_x) (Subpart Ea only), and carbon monoxide (CO). Additionally, standards for mercury (Hg), lead (Pb), cadmium (Cd), and NO_x (for Subpart Ca) are currently being considered for new and existing facilities, as required by Section 129 of the Clean Air Act Amendments (CAAA) of 1990.

In addition to requiring revisions of the Subpart Ca and Ea regulations to include these additional pollutants, Section 129 also requires the EPA to review the standards and guidelines for the pollutants currently covered under these subparts. It is likely that the revised regulations will be more stringent. The regulations are also being expanded to cover new and existing MWC facilities with capacities of 225 Mg/day (250 tpd) or less. The revised regulations will likely cover facilities with capacities as low as 18 to 45 Mg/day (20 to 50 tpd). These facilities are currently subject only to State regulations.

2.1.1.1 Combustor Technology -- There are three main classes of technologies used to combust MSW: mass burn, refuse-derived fuel (RDF), and modular combustors. This section provides a general description of these three classes of combustors. Section 2.1.2 provides more details regarding design and operation of each combustor class.

With mass burn units, the MSW is combusted without any preprocessing other than removal of items too large to go through the feed system. In a typical mass burn combustor, refuse is placed on a grate that moves through the combustor. Combustion air in excess of stoichiometric amounts is

supplied both below (underfire air) and above (overfire air) the grate. Mass burn combustors are usually erected at the site (as opposed to being prefabricated at another location), and range in size from 46 to 900 Mg/day (50 to 1,000 tpd) of MSW throughput per unit. The mass burn combustor category can be divided into mass burn/waterwall (MB/WW), mass burn/rotary waterwall combustor (MB/RC), and mass burn refractory wall (MB/REF) designs. Mass burn/waterwall designs have water-filled tubes in the furnace walls that are used to recover heat for production of steam and/or electricity. Mass burn/rotary waterwall combustors use a rotary combustion chamber constructed of water-filled tubes followed by a waterwall furnace. Mass burn refractory designs are older and typically do not include any heat recovery. Process diagrams for a typical MB/WW combustor, a MB/RC combustor, and one type of MB/REF combustor are presented in Figures 2.1-1, 2.1-2 and 2.1-3, respectively.

Refuse-derived fuel combustors burn processed waste that varies from shredded waste to finely divided fuel suitable for co-firing with pulverized coal. Combustor sizes range from 290 to 1,300 Mg/day (320 to 1,400 tpd). A process diagram for a typical RDF combustor is shown in Figure 2.1-4. Waste processing usually consists of removing noncombustibles and shredding, which generally raises the heating value and provides a more uniform fuel. The type of RDF used depends on the boiler design. Most boilers designed to burn RDF use spreader stokers and fire fluff RDF in a semi-suspension mode. A subset of the RDF technology is fluidized bed combustors (FBC).

Modular combustors are similar to mass burn combustors in that they burn waste that has not been pre-processed, but they are typically shop fabricated and generally range in size from 4 to 130 Mg/day (5 to 140 tpd) of MSW throughput. One of the most common types of modular combustors is the starved air or controlled air type, which incorporates two combustion chambers. A process diagram of a typical modular starved-air (MOD/SA) combustor is presented in Figure 2.1-5. Air is supplied to the primary chamber at sub-stoichiometric levels. The incomplete combustion products (CO and organic compounds) pass into the secondary combustion chamber where additional air is added and combustion is completed. Another type of modular combustor design is the modular excess air (MOD/EA) combustor which consists of two chambers as with MOD/SA units, but is functionally similar to mass burn unit in that it uses excess air in the primary chamber.

2.1.2 Process Description[4]

Types of combustors described in this section include:

- Mass burn waterwall,
- Mass burn rotary waterwall,
- Mass burn refractory wall,
- Refuse-derived fuel-fired,
- Fluidized bed,
- Modular starved air, and
- Modular excess air.

2.1.2.1 Mass Burn Waterwall Combustors -- The MB/WW design represents the predominant technology in the existing population of large MWCs, and it is expected that over 50 percent of new

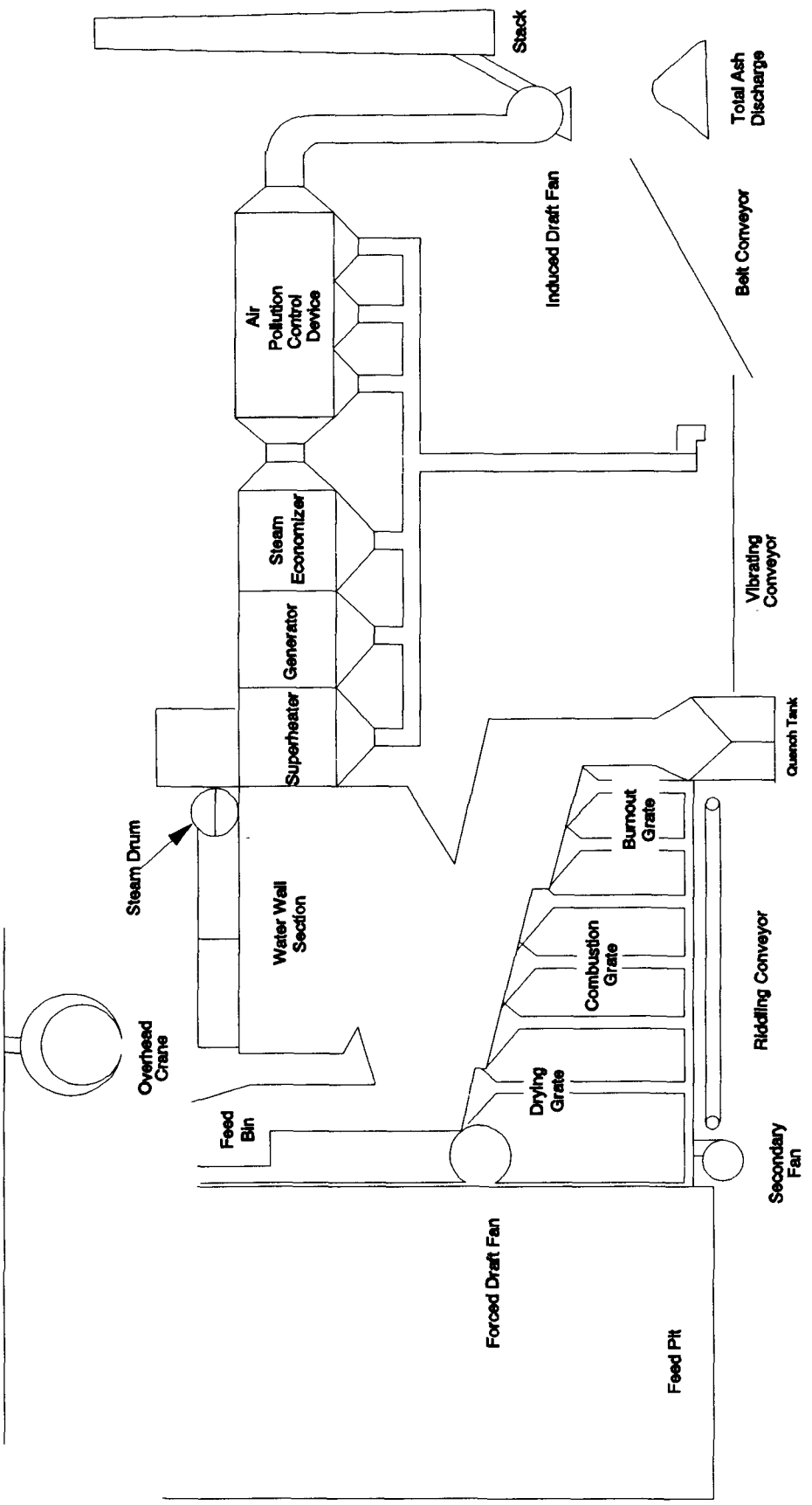


Figure 2.1-1. Typical mass burn waterwall combustor.

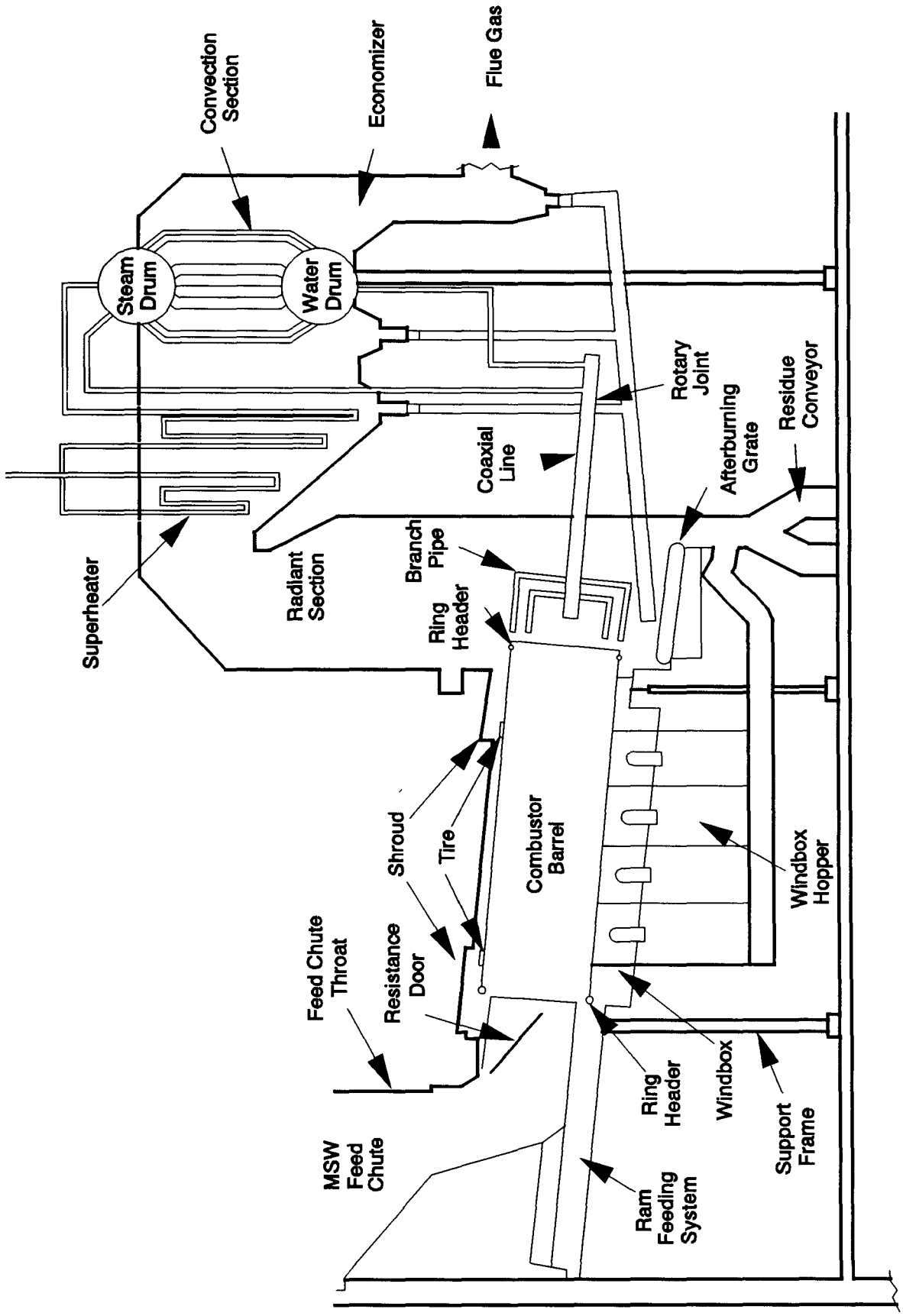


Figure 2.1-2. Simplified process flow diagram, gas cycle for a rotary waterwall combustor.

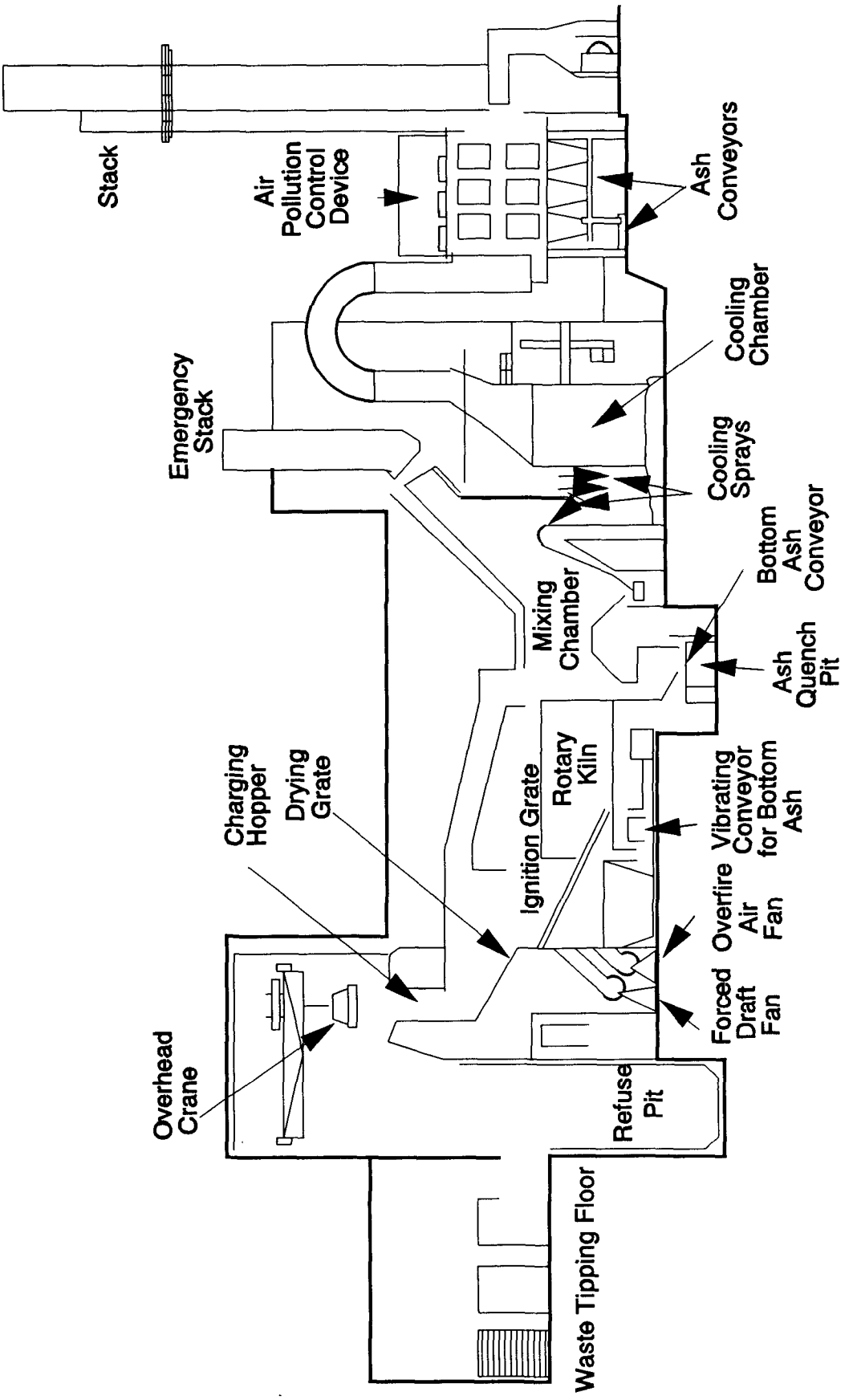


Figure 2.1-3. Mass burn refractory-wall combustor with grate/rotary kiln.

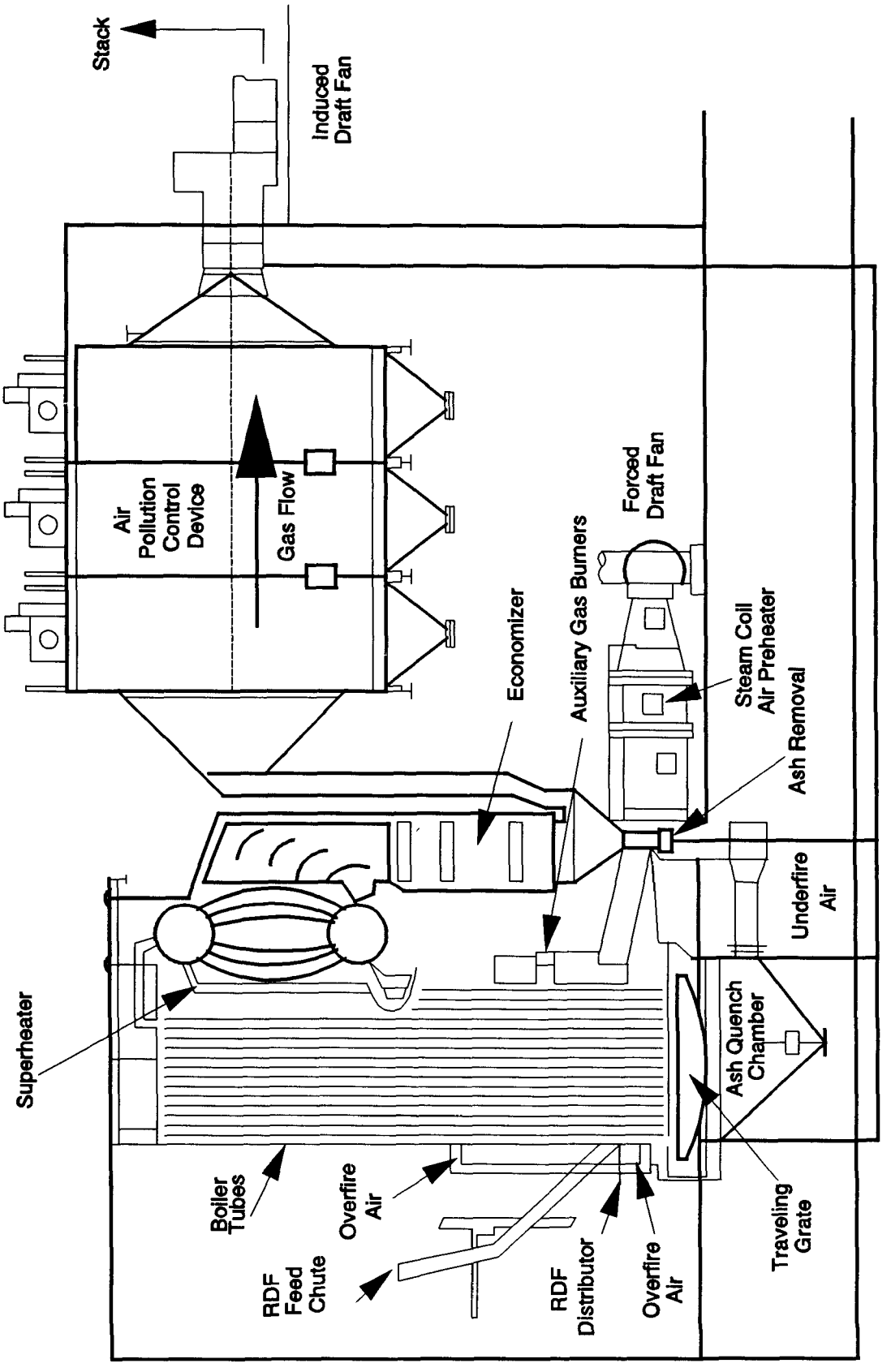


Figure 2.1-4. Typical RDF-fired spreader stoker boiler.

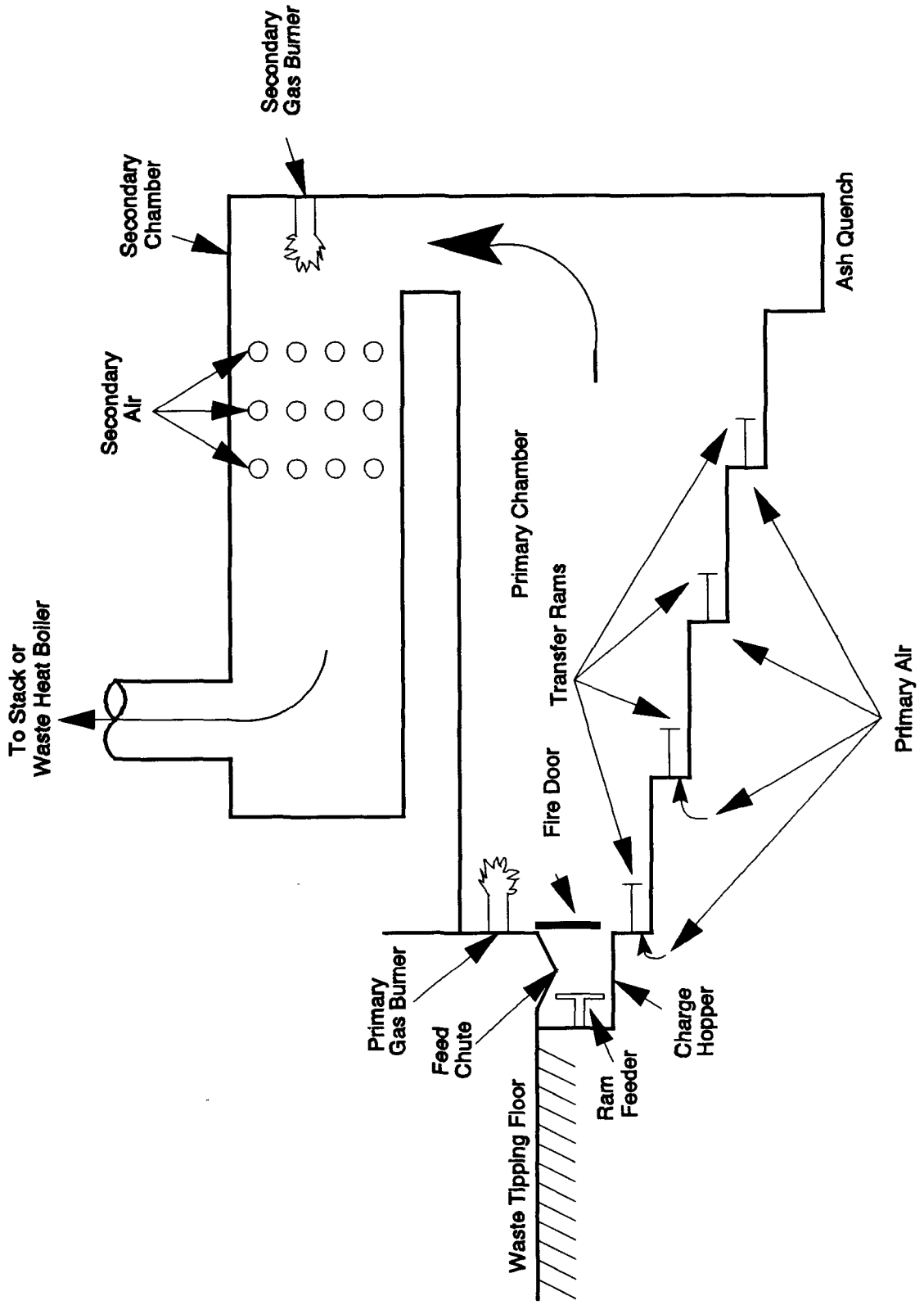


Figure 2.1-5. Typical modular starved-air combustor with transfer rams.

units will be MB/WW designs. In MB/WW units, the combustor walls are constructed of metal tubes that contain circulating pressurized water used to recover heat from the combustion chamber. In the lower actively burning region of the chamber where corrosive conditions may exist, the walls are generally lined with castable refractory. Heat is also recovered in the convective sections (i.e., superheater, economizer) of the combustor.

With this type of system, unprocessed waste (after removal of large, bulky items) is delivered by an overhead crane to a feed hopper, which conveys the waste into the combustion chamber. Earlier MB/WW designs utilized gravity feeders, but it is now more typical to feed by means of single or dual hydraulic rams.

Nearly all modern MB/WW facilities utilize reciprocating grates or roller grates to move the waste through the combustion chamber. The grates typically include three sections. On the initial grate section, referred to as the drying grate, the moisture content of the waste is reduced prior to ignition. The second grate section, referred to as the burning grate, is where the majority of active burning takes place. The third grate section, referred to as the burnout or finishing grate, is where remaining combustibles in the waste are burned. Smaller units may have only two individual grate sections. Bottom ash is discharged from the finishing grate into a water-filled ash quench pit or ram discharger. From there, the moist ash is discharged to a conveyor system and transported to an ash load-out or storage area prior to disposal. Dry ash systems have been used in some designs, but their use is not widespread.

Combustion air is added from beneath the grate by way of underfire air plenums. The majority of MB/WW systems supply underfire air to the individual grate sections through multiple plenums, which enhance the ability to control burning and heat release from the waste bed. Overfire air is injected through rows of high-pressure nozzles located in the side walls of the combustor to oxidize fuel-rich gases evolved from the bed and complete the combustion process. Properly designed and operated overfire air systems are essential for good mixing and burnout of organics in the flue gas. Typically, MB/WW MWCs are operated with 80 to 100 percent excess air.

The flue gas exits the combustor and passes through additional heat recovery sections to one or more air pollution control devices (APCD). The types of APCDs that may be used are discussed in Section 2.1.4.

2.1.2.2 Mass Burn Rotary Waterwall Combustors -- A more unique mass burn design is the MB/RC. Plants of this design range in size from 180 to 2,400 Mg/day (200 to 2,700 tpd), with typically two or three units per plant. This type of system uses a rotary combustion chamber. Following pre-sorting of objects too large to fit in the combustor, the waste is ram fed to the inclined rotary combustion chamber, which rotates slowly, causing the waste to advance and tumble as it burns. Underfire air is injected through the waste bed, and overfire air is provided above the waste bed. Bottom ash is discharged from the rotary combustor to an afterburner grate and then into a wet quench pit. From there, the moist ash is conveyed to an ash load-out or storage area prior to disposal.

Approximately 80 percent of the combustion air is provided along the rotary combustion chamber length, with most of the air provided in the first half of the chamber. The rest of the combustion air is supplied to the afterburner grate and above the rotary combustor outlet in the boiler. The MB/RC operates at about 50 percent excess air, compared with 80 to 100 percent for typical MB/WW firing systems. Water flowing through the tubes in the rotary chamber recovers heat from

combustion. Additional heat recovery occurs in the boiler waterwall, superheater, and economizer. From the economizer, the flue gas is typically routed to APCDs.

2.1.2.3 Mass Burn Refractory Wall Combustors -- Prior to 1970 there were numerous MB/REF MWCs in operation. The purpose of these plants was to achieve waste reduction; energy recovery was generally not incorporated in their design. Most of the roughly 25 MB/REF plants that still operate or that were built in the 1970s and 1980s use electrostatic precipitators (ESPs) to reduce PM emissions, and several have heat recovery boilers. Most MB/REF combustors have unit sizes of 90 to 270 Mg/day (100 to 300 tpd). It is not expected that additional plants of this design will be built in the United States.

The MB/REF combustors comprise several designs. One design involves a batch-fed upright combustor, which may be cylindrical or rectangular in shape. A second design is based on a rectangular combustion chamber with a traveling, rocking, or reciprocating grate. This type of combustor is continuously fed and operates in an excess air mode. If the waste is moved on a traveling grate, it is not sufficiently aerated as it advances through the combustor. As a result, waste burnout or complete combustion is inhibited by fuel bed thickness, and there is considerable potential for unburned waste to be discharged into the bottom ash pit. Rocking and reciprocating grate systems stir and aerate the waste bed as it advances through the combustion chamber, thereby improving contact between the waste and combustion air and increasing the burnout of combustibles. The system generally discharges the ash at the end of the grate to a water quench pit for collection and disposal in a landfill.

Because MB/REF combustors do not contain a heat transfer medium (such as the waterwalls that are present in modern energy recovery units), they typically operate at higher excess air rates (150 to 300 percent) than MB/WW combustors (80 to 100 percent). The higher excess air levels are required to prevent excessive temperatures, which can result in refractory damage, slagging, fouling, and corrosion problems. One adverse effect of higher excess air levels is the potential for increased carryover of PM from the combustion chamber and, ultimately, increased stack emission rates. High PM carryover may also contribute to increased CDD/CDF emissions by providing increased surface area for downstream catalytic formation to take place. A second problem is the potential for high excess air levels to quench (cool) the combustion reactions, preventing thermal destruction of organic species.

An alternate, newer MB/REF combustor is the Volund design (Figure 2.1-3 presents this MB/REF design). This design minimizes some of the problems of other MB/REF systems. A refractory arch is installed above the combustion zone to reduce radiant heat losses and improve solids burnout. The refractory arch also routes part of the rising gases from the drying and combustion grates through a gas by-pass duct to the mixing chamber. There the gas is mixed with gas from the burnout grate or kiln. Bottom ash is conveyed to an ash quench pit. Volund MB/REF combustors operate with 80 to 120 percent excess air, which is more in line with excess air levels in the MB/WW designs. As a result, lower CO levels and better organics destruction are achievable, as compared to other MB/REF combustors.

2.1.2.4 Refuse-derived Fuel Combustors -- Refuse-derived fuel combustors burn MSW that has been processed to varying degrees, from simple removal of bulky and noncombustible items accompanied by shredding, to extensive processing to produce a finely divided fuel suitable for co-firing in pulverized coal-fired boilers. Processing MSW to RDF generally raises the heating value of the waste because many of the noncombustible items are removed.

A set of standards for classifying RDF types has been established by the American Society for Testing and Materials. The type of RDF used is dependent on the boiler design. Boilers that are designed to burn RDF as the primary fuel usually utilize spreader stokers and fire fluff RDF in a semi-suspension mode. This mode of feeding is accomplished by using an air swept distributor, which allows a portion of the RDF to burn in suspension and the remainder to be burned out after falling on a horizontal traveling grate. The number of RDF distributors in a single unit varies directly with unit capacity. The distributors are normally adjustable so that the trajectory of the waste feed can be varied. Because the traveling grate moves from the rear to the front of the furnace, distributor settings are adjusted so that most of the waste lands on the rear two-thirds of the grate. This allows more time for combustion to be completed on the grate. Bottom ash drops into a water-filled quench chamber. Some traveling grates operate at a single speed, but most can be manually adjusted to accommodate variations in burning conditions. Underfire air is normally preheated and introduced beneath the grate by a single plenum. Overfire air is injected through rows of high-pressure nozzles, providing a zone for mixing and completion of the combustion process. These combustors typically operate at 80 to 100 percent excess air.

Due to the basic design of the semi-suspension feeding systems, PM levels at the inlet to the pollution control device are typically double those of mass burn systems and more than an order of magnitude higher than MOD/SA combustors. The higher particulate loadings may contribute to the catalytic formation of CDD/CDF. However, controlled Hg emissions from these plants are considerably lower than from mass burn plants as a result of the higher levels of carbon present in the PM carryover, as Hg adsorbs onto the carbon and can be subsequently captured by the PM control device.

Pulverized coal-(PC) fired boilers can co-fire fluff RDF or powdered RDF. In a PC-fired boiler that co-fires fluff with pulverized coal, the RDF is introduced into the combustor by air transport injectors that are located above or even with the coal nozzles. Due to its high moisture content and large particle size, RDF requires a longer burnout time than coal. A significant portion of the larger, partially burned particles disengage from the gas flow and fall onto stationary drop grates at the bottom of the furnace where combustion is completed. Ash that accumulates on the grate is periodically dumped into the ash hopper below the grate. Refuse-derived fuel can also be co-fired with coal in stoker-fired boilers.

2.1.2.5 Fluidized Bed Combustors -- In an FBC, fluff or pelletized RDF is combusted on a turbulent bed of noncombustible material such as limestone, sand, or silica. In its simplest form, an FBC consists of a combustor vessel equipped with a gas distribution plate and underfire air windbox at the bottom. The combustion bed overlies the gas distribution plate. The combustion bed is suspended or "fluidized" through the introduction of underfire air at a high flow rate. The RDF may be injected into or above the bed through ports in the combustor wall. Other wastes and supplemental fuel may be blended with the RDF outside the combustor or added into the combustor through separate openings. Overfire air is used to complete the combustion process.

There are two basic types of FBC systems: bubbling bed and circulating bed. With bubbling bed combustors, most of the fluidized solids are maintained near the bottom of the combustor by using relatively low air fluidization velocities. This helps reduce the entrainment of solids from the bed into the flue gas, minimizing recirculation or reinjection of bed particles. In contrast, circulating bed combustors operate at relatively high fluidization velocities to promote carryover of solids into the upper section of the combustor. Combustion occurs in both the bed and upper section of the combustor. By design, a fraction of the bed material is entrained in the combustion gas and enters a

cyclone separator which recycles unburned waste and inert particles to the lower bed. Some of the ash is removed from the cyclone with the solids from the bed.

Good mixing is inherent in the FBC design. Fluidized bed combustors have very uniform gas temperatures and mass compositions in both the bed and in the upper region of the combustor. This allows the FBCs to operate at lower excess air and temperature levels than conventional combustion systems. Waste-fired FBCs typically operate at excess air levels between 30 and 100 percent and at bed temperatures around 815°C (1,500°F). Low temperatures are necessary for waste-firing FBCs because higher temperatures lead to bed agglomeration.

2.1.2.6 Modular Starved-air (Controlled-air) Combustors -- In terms of number of facilities, MOD/SA combustors represent a large segment of the existing MWC population. However, because of their small sizes, they account for only a small percent of the total capacity. The basic design of a MOD/SA combustor consists of two separate combustion chambers, referred to as the "primary" and "secondary" chambers. Waste is batch-fed to the primary chamber by a hydraulically activated ram. The charging bin is filled by a front end loader or other means. Waste is fed automatically on a set frequency, with generally 6 to 10 minutes between charges.

Waste is moved through the primary combustion chamber by either hydraulic transfer rams or reciprocating grates. Combustors using transfer rams have individual hearths upon which combustion takes place. Grate systems generally include two separate grate sections. In either case, waste retention times in the primary chamber are long, lasting up to 12 hours. Bottom ash is usually discharged to a wet quench pit.

The quantity of air introduced into the primary chamber defines the rate at which waste burns. Combustion air is introduced in the primary chamber at sub-stoichiometric levels, resulting in a flue gas rich in unburned hydrocarbons. The combustion air flow rate to the primary chamber is controlled to maintain an exhaust gas temperature set point, generally 650 to 980°C (1,200 to 1,800°F), which corresponds to about 40 to 60 percent theoretical air.

As the hot, fuel-rich flue gases flow to the secondary chamber, they are mixed with additional air to complete the burning process. Because the temperature of the exhaust gases from the primary chamber is above the autoignition point, completing combustion is simply a matter of introducing air into the fuel-rich gases. The amount of air added to the secondary chamber is controlled to maintain a desired flue gas exit temperature, typically 980 to 1,200°C (1,800 to 2,200°F). Approximately 80 percent of the total combustion air is introduced as secondary air. Typical excess air levels vary from 80 to 150 percent.

The walls of both combustion chambers are refractory lined. Early MOD/SA combustors did not include energy recovery, but a waste heat boiler is common in newer installations, with two or more combustion modules manifolded to a single boiler. Combustors with energy recovery capabilities also maintain dump stacks for use in an emergency, or when the boiler and/or air pollution control equipment are not in operation.

Most MOD/SA MWCs are equipped with auxiliary fuel burners located in both the primary and secondary combustion chambers. Auxiliary fuel can be used during startup (many modular units do not operate continuously) or when problems are experienced maintaining desired combustion temperatures. In general, the combustion process is self-sustaining through control of air flow and feed rate, so that continuous co-firing of auxiliary fuel is normally not necessary.

The high combustion temperatures and proper mixing of flue gas with air in the secondary combustion chamber provide good combustion, resulting in relatively low CO and trace organic emissions. Because of the limited amount of combustion air introduced through the primary chamber, gas velocities in the primary chamber and the amount of entrained PM are low. As a result, PM emissions of air pollutants from MOD/SA MWCs are relatively low. Many existing modular systems do not have air pollution controls. This is especially true of the smaller starved-air facilities. A few of the newer MOD/SA MWCs have acid gas/PM controls.

2.1.2.7 Modular Excess Air Combustors -- There are fewer MOD/EA MWCs than MOD/SA MWCs. The design of MOD/EA units is similar to that of MOD/SA units, including the presence of primary and secondary combustion chambers. Waste is batch-fed to the primary chamber, which is refractory-lined. The waste is moved through the primary chamber by hydraulic transfer rams, oscillating grates, or a revolving hearth. Bottom ash is discharged to a wet quench pit. Additional flue gas residence time for fuel/carbon burnout is provided in the secondary chamber, which is also refractory-lined. Energy is typically recovered in a waste heat boiler. Facilities with multiple combustors may have a tertiary chamber where flue gases from each combustor are mixed prior to entering the energy recovery boiler.

Unlike the MOD/SA combustors but similar to MB/REF units, a MOD/EA combustor typically operates at about 100 percent excess air in the primary chamber, but may vary between 50 and 250 percent excess air. The MOD/EA combustors also use recirculated flue gas for combustion air to maintain desired temperatures in the primary and secondary chambers. Due to higher air velocities, PM emissions from MOD/EA combustors are higher than those from MOD/SA combustors and are more similar in concentration to PM emissions from mass burn units. However, NO_x emissions from MOD/EA combustors appear to be lower than from either MOD/SA or mass burn units.

2.1.3 Emissions[4-7]

Depending on the characteristics of the MSW and combustion conditions in the MWC, the following pollutants can be emitted:

- PM,
- Metals (in solid form on PM, except for Hg),
- Acid gases (HCl, SO_2),
- CO,
- NO_x, and
- Toxic organics (most notably CDD/CDF).

A brief discussion on each of the pollutants is provided below, along with discussions on controls used to reduce emissions of these pollutants to the atmosphere.

2.1.3.1 Particulate Matter -- The amount of PM exiting the furnace of an MWC depends on the waste characteristics, the physical nature of the combustor design, and the combustor's operation. Under normal combustion conditions, solid fly ash particulates formed from inorganic,

noncombustible constituents in MSW are released into the flue gas. Most of this particulate is captured by the facility's APCD and are not emitted to the atmosphere.

Particulate matter can vary greatly in size with diameters ranging from less than one micrometer to hundreds of micrometers (μm). Fine particulates, having diameters less than 10μm (known as PM-10), are of increased concern because a greater potential for inhalation and passage into the pulmonary region exists. Further, acid gases, metals, and toxic organics may preferentially adsorb onto particulates in this size range. The NSPS and EG for MWCs regulate total PM, while PM-10 is of interest for State Implementation Plans and when dealing with ambient PM concentrations. In this chapter, "PM" refers to total PM as measured by EPA Reference Method 5.

The level of PM emissions at the inlet of the APCD will vary according the combustor design, air distribution, and waste characteristics. For example, facilities that operate with high underfire/overfire air ratios or relatively high excess air levels may entrain greater quantities of PM and have high PM levels at the APCD inlet. For combustors with multiple-pass boilers that change the direction of the flue gas flow, part of the PM may be removed prior to the APCD. Lastly, the physical properties of the waste being fed and the method of feeding influences PM levels in the flue gas. Typically, RDF units have higher PM carryover from the furnace due to the suspension-feeding of the RDF. However, controlled PM emissions from RDF plants do not vary substantially from other MWCs (i.e., MB/WW), because the PM is efficiently collected in the APCD.

2.1.3.2 Metals -- Metals are present in a variety of MSW streams, including paper, newsprint, yard wastes, wood, batteries, and metal cans. The metals present in MSW are emitted from MWCs in association with PM [e.g., arsenic (As), Cd, chromium (Cr), and Pb] and as vapors, such as Hg. Due to the variability in MSW composition, metal concentrations are highly variable and are essentially independent of combustor type. If the vapor pressure of a metal is such that condensation onto particulates in the flue gas is possible, the metal can be effectively removed by the PM control device. With the exception of Hg, most metals have sufficiently low vapor pressures to result in almost all of the metals being condensed. Therefore, removal in the PM control device for these metals is generally greater than 98 percent. Mercury, on the other hand, has a high vapor pressure at typical APCD operating temperatures, and capture by the PM control device is highly variable. The level of carbon in the fly ash appears to affect the level of Hg control. A high level of carbon in the fly ash can enhance Hg adsorption onto particles removed by the PM control device.

2.1.3.3 Acid Gases -- The chief acid gases of concern from the combustion of MSW are HCl and SO_2. Hydrogen fluoride (HF), hydrogen bromide (HBr), and sulfur trioxide (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 contents vary considerably based on seasonal and local waste variations. Emissions of SO_2 and HCl from MWCs depend on the chemical form of sulfur and chlorine 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. Acid gas concentrations are considered to be independent of combustion conditions. The major sources of chlorine in MSW are paper and plastics. Sulfur is contained in many constituents of MSW, such as asphalt shingles, gypsum wallboard, and tires. Because RDF processing does not generally impact the distribution of combustible materials in the waste fuel, HCl and SO_2 concentrations for mass burn and RDF units are similar.

2.1.3.4 Carbon Monoxide -- Carbon monoxide emissions result when all of the carbon in the waste is not oxidized to carbon dioxide (CO_2). High levels of CO indicate that the combustion gases were not held at a sufficiently high temperature in the presence of oxygen (O_2) for a long enough time to

convert CO to CO_2. As waste burns in a fuel bed, it releases CO, hydrogen (H_2), and unburned hydrocarbons. Additional air then reacts with the gases escaping from the fuel bed to convert CO and H_2 to CO_2 and H_2O. Adding too much air to the combustion zone will lower the local gas temperature and quench (retard) the oxidation reactions. If too little air is added, the probability of incomplete mixing increases, allowing greater quantities of unburned hydrocarbons to escape the furnace. Both of the conditions would result in increased emissions of CO.

Because O_2 levels and air distributions vary among combustor types, CO levels also vary among combustor types. For example, semi-suspension-fired RDF units generally have higher CO levels than mass burn units, due to the effects of carryover of incompletely combusted materials into low temperature portions of the combustor, and, in some cases, due to instabilities that result from fuel feed characteristics.

Carbon monoxide concentration is a good indicator of combustion efficiency, and is an important criterion for indicating instabilities and nonuniformities in the combustion process. It is during unstable combustion conditions that more carbonaceous material is available and higher CDD/CDF and organic hazardous air pollutant levels occur. The relationship between emissions of CDD/CDF and CO indicates that high levels of CO (several hundred parts per million by volume [ppmv]), corresponding to poor combustion conditions, frequently correlate with high CDD/CDF emissions. When CO levels are low, however, correlations between CO and CDD/CDF are not well defined (due to the fact that many mechanisms may contribute to CDD/CDF formation), but CDD/CDF emissions are generally lower.

2.1.3.5 Nitrogen Oxides -- Nitrogen oxides are products of all fuel/air combustion processes. Nitric oxide (NO) is the primary component of NO_x; however, nitrogen dioxide (NO_2) and nitrous oxide (N_2O) are also formed in smaller amounts. The combination of the compounds is referred to as NO_x. Nitrogen oxides are formed during combustion through (1) oxidation of nitrogen in the waste, and (2) fixation of atmospheric nitrogen. Conversion of nitrogen in the waste occurs at relatively low temperatures [less than 1,090°C (2,000°F)], while fixation of atmospheric nitrogen occurs at higher temperatures. Because of the relatively low temperatures at which MWC furnaces operate, 70 to 80 percent of NO_x formed in MWCs is associated with nitrogen in the waste.

2.1.3.6 Organic Compounds -- A variety of organic compounds, including CDD/CDF, chlorobenzene (CB), polychlorinated biphenyls (PCBs), chlorophenols (CPs), and polyaromatic hydrocarbons (PAHs) are present in MSW or can be formed during the combustion and post-combination processes. Organics in the flue gas can exist in the vapor phase or can be condensed or absorbed on fine particulates. Control of organics is accomplished through proper design and operation of both the combustor and the APCDs.

Based on potential health effects, CDD/CDF has been a focus of many research and regulatory activities. Due to toxicity levels, attention is most often placed on levels of CDD/CDF in the tetra- through octa-homolog groups and specific isomers within those groups that have chlorine substituted in the 2, 3, 7, and 8 positions. As noted earlier, the NSPS and EG for MWCs regulate the total tetra- through octa-CDD/CDF.

2.1.4 Controls[8-10]

A wide variety of control technologies are used to control emissions from MWCs. The control of PM, along with metals that have adsorbed onto the PM, is most frequently accomplished through the use of an ESP or fabric filter (FF). Although other PM control technologies (e.g.,

cyclones, electrified gravel beds, and venturi scrubbers) are available, they are seldom used on existing systems, and it is anticipated that they will not be frequently used in future MWC systems. The control of acid gas emissions (i.e., SO_2 and HCl) is most frequently accomplished through the application of acid gas control technologies such as spray drying or dry sorbent injection, followed by a high efficiency PM control device. Some facilities use a wet scrubber to control acid gases. It is anticipated that dry systems (spray drying and dry sorbent injection) will be more widely used than wet scrubbers on future U. S. MWC systems. Each of these technologies is discussed in more detail below.

2.1.4.1 Electrostatic Precipitators -- Electrostatic precipitators consist of a series of high-voltage (20 to 100 kilovolts) discharge electrodes and grounded metal plates through which PM-laden flue gas flows. Negatively charged ions formed by this high-voltage field (known as a "corona") attach to PM in the flue gas, causing the charged particles to migrate toward, and be collected on, the grounded plates. The most common types of ESPs used by MWCs are (1) plate wire units in which the discharge electrode is a bottom weighted or rigid wire, and (2) flat plate units which use flat plates rather than wires as the discharge electrode.

As a general rule, the greater the amount of collection plate area, the greater the ESP's PM collection efficiency. Once the charged particles are collected on the grounded plates, the resulting dust layer is removed from the plates by rapping, washing, or some other method and collected in a hopper. When the dust layer is removed, some of the collected PM becomes re-entrained in the flue gas. To assure good PM collection efficiency during plate cleaning and electrical upsets, ESPs have several fields located in series along the direction of flue gas flow that can be energized and cleaned independently. Particles re-entrained when the dust layer is removed from one field can be recollected in a downstream field. Because of this phenomena, increasing the number of fields generally improves PM removal efficiency.

Small particles generally have lower migration velocities than large particles and are therefore more difficult to collect. This factor is especially important to MWCs because of the large amount of total fly ash smaller than 1 μm. As compared to pulverized coal fired combustors, in which only 1 to 3 percent of the fly ash is generally smaller than 1 μm, 20 to 70 percent of the fly ash at the inlet of the PM control device for MWCs is reported to be smaller than 1 μm. As a result, effective collection of PM from MWCs requires greater collection areas and lower flue gas velocities than many other combustion types.

As an approximate indicator of collection efficiency, the specific collection area (SCA) of an ESP is frequently used. The SCA is calculated by dividing the collecting electrode plate area by the flue gas flow rate and is expressed as square feet of collecting area per 28 cubic meters per minute (1000 cubic feet per minute) of flue gas. In general, the higher the SCA, the higher the collection efficiency. Most ESPs at newer MWCs have SCAs in the range of 400 to 600. When estimating emissions from ESP-equipped MWCs, the SCA of the ESP should be taken into consideration. Not all ESPs are designed equally and performance of different ESPs will vary.

2.1.4.2 Fabric Filters -- Fabric filters are also used for PM and metals control, particularly in combination with acid gas control and flue gas cooling. Fabric filters (also known as "baghouses") remove PM by passing flue gas through a porous fabric that has been sewn into a cylindrical bag. Multiple individual filter bags are mounted in an arranged compartment. A complete FF, in turn, consists of 4 to 16 individual compartments that can be independently operated.

As the flue gas flows through the filter bags, particulate is collected on the filter surface, mainly through inertial impaction. The collected particulate builds up on the bag, forming a filter cake. As the thickness of the filter cake increases, the pressure drop across the bag also increases. Once pressure drop across the bags in a given compartment becomes excessive, that compartment is generally taken off-line, mechanically cleaned, and then placed back on-line.

Fabric filters are generally differentiated by cleaning mechanisms. Two main filter cleaning mechanisms are used: reverse-air and pulse-jet. In a reverse-air FF, flue gas flows through unsupported filter bags, leaving the particulate on the inside of the bags. The particulate builds up to form a particulate filter cake. Once excessive pressure drop across the filter cake is reached, air is blown through the filter in the opposite direction, the filter bag collapses, and the filter cake falls off and is collected. In a pulse-jet FF, flue gas flows through supported filter bags leaving particulate on the outside of the bags. To remove the particulate filter cake, compressed air is pulsed through the inside of the filter bag, the filter bag expands and collapses to its pre-pulsed shape, and the filter cake falls off and is collected.

2.1.4.3 Spray Drying -- Spray dryers (SD) are the most frequently used acid gas control technology for MWCs in the United States. When used in combination with an ESP or FF, the system can control CDD/CDF, PM (and metals), SO_2, and HCl emissions from MWCs. Spray dryer/fabric filter systems are more common than SD/ESP systems and are used mostly on new, large MWCs. In the spray drying process, lime slurry is injected into the SD through either a rotary atomizer or dual-fluid nozzles. The water in the slurry evaporates to cool the flue gas, and the lime reacts with acid gases to form calcium salts that can be removed by a PM control device. The SD is designed to provide sufficient contact and residence time to produce a dry product before leaving the SD adsorber vessel. The residence time in the adsorber vessel is typically 10 to 15 seconds. The particulate leaving the SD contains fly ash plus calcium salts, water, and unreacted hydrated lime.

The key design and operating parameters that significantly affect SD performance are SD outlet temperature and lime-to-acid gas stoichiometric ratio. The SD outlet approach to saturation temperature is controlled by the amount of water in the slurry. More effective acid gas removal occurs at lower approach to saturation temperatures, but the temperature must be high enough to ensure the slurry and reaction products are adequately dried prior to collection in the PM control device. For MWC flue gas containing significant chlorine, a minimum SD outlet temperature of around 115°C (240°F) is required to control agglomeration of PM and sorbent by calcium chloride. Outlet gas temperature from the SD is usually around 140°C (285°F).

The stoichiometric ratio is the molar ratio of calcium in the lime slurry fed to the SD divided by the theoretical amount of calcium required to completely react with the inlet HCl and SO_2 in the flue gas. At a ratio of 1.0, the moles of calcium are equal to the moles of incoming HCl and SO_2. However, because of mass transfer limitations, incomplete mixing, differing rates of reaction (SO_2 reacts more slowly than HCl), more than the theoretical amount of lime is generally fed to the SD. The stoichiometric ratio used in SD systems varies depending on the level of acid gas reduction required, the temperature of the flue gas at the SD exit, and the type of PM control device used. Lime is fed in quantities sufficient to react with the peak acid gas concentrations expected without severely decreasing performance. The lime content in the slurry is generally about 10 percent by weight, but cannot exceed approximately 30 percent by weight without clogging of the lime slurry feed system and spray nozzles.

2.1.4.4 Dry Sorbent Injection -- This type of technology has been developed primarily to control acid gas emissions. However, when combined with flue gas cooling and either an ESP or FF,

sorbent injection processes may also control CDD/CDF and PM emissions from MWCs. Two primary subsets of dry sorbent injection technologies exist. The more widely used of these approaches, referred to as duct sorbent injection (DSI), involves injecting dry alkali sorbents into flue gas downstream of the combustor outlet and upstream of the PM control device. The second approach, referred to as furnace sorbent injection (FSI), injects sorbent directly into the combustor.

In DSI, powdered sorbent is pneumatically injected into either a separate reaction vessel or a section of flue gas duct located downstream of the combustor economizer or quench tower. Alkali in the sorbent (generally calcium or sodium) reacts with HCl, HF, and SO_2 to form alkali salts [e.g., calcium chloride ($CaCl_2$), calcium fluoride (CaF_2), and calcium sulfite ($CaSO_3$)]. By lowering the acid content of the flue gas, downstream equipment can be operated at reduced temperatures while minimizing the potential for acid corrosion of equipment. Solid reaction products, fly ash, and unreacted sorbent are collected with either an ESP or FF.

Acid gas removal efficiency with DSI depends on the method of sorbent injection, flue gas temperature, sorbent type and feed rate, and the extent of sorbent mixing with the flue gas. Not all DSI systems are of the same design, and performance of the systems will vary. Flue gas temperature at the point of sorbent injection can range from about 150 to 320°C (300 to 600°F) depending on the sorbent being used and the design of the process. Sorbents that have been successfully tested include hydrated lime ($Ca(OH)_2$), soda ash (Na_2CO_3), and sodium bicarbonate ($NaHCO_3$). Based on published data for hydrated lime, some DSI systems can achieve removal efficiencies comparable to SD systems; however, performance is generally lower.

By combining flue gas cooling with DSI, it may be possible to increase CDD/CDF removal through a combination of vapor condensation and adsorption onto the sorbent surface. Cooling may also benefit PM control by decreasing the effective flue gas flow rate (i.e., cubic meters per minute) and reducing the resistivity of individual particles.

Furnace sorbent injection involves the injection of powdered alkali sorbent (either lime or limestone) into the furnace section of a combustor. This can be accomplished by addition of sorbent to the overfire air, injection through separate ports, or mixing with the waste prior to feeding to the combustor. As with DSI, reaction products, fly ash, and unreacted sorbent are collected using an ESP or FF.

The basic chemistry of FSI is similar to DSI. Both use a reaction of sorbent with acid gases to form alkali salts. However, several key differences exist in these two approaches. First, by injecting sorbent directly into the furnace [at temperatures of 870 to 1,200°C (1,600 to 2,200°F)] limestone can be calcined in the combustor to form more reactive lime, thereby allowing use of less expensive limestone as a sorbent. Second, at these temperatures, SO_2 and lime react in the combustor, thus providing a mechanism for effective removal of SO_2 at relatively low sorbent feed rates. Third, by injecting sorbent into the furnace rather than into a downstream duct, additional time is available for mixing and reaction between the sorbent and acid gases. Fourth, if a significant portion of the HCl is removed before the flue gas exits the combustor, it may be possible to reduce the formation of CDD/CDF in latter sections of the flue gas ducting. However, HCl and lime do not react with each other at temperatures above 760°C (1,400°F). This is the flue gas temperature that exists in the convective sections of the combustor. Therefore, HCl removal may be lower than with DSI. Potential disadvantages of FSI include fouling and erosion of convective heat transfer surfaces by the injected sorbent.

2.1.4.5 Wet Scrubbers -- Many types of wet scrubbers have been used for controlling acid gas emissions from MWCs. These include spray towers, centrifugal scrubbers, and venturi scrubbers. Wet scrubbing technology has primarily been used in Japan and Europe. Currently, it is not anticipated that many new MWCs being built in the United States will use this type of acid gas control system. Wet scrubbing normally involves passing the flue gas through an ESP to reduce PM, followed by a one- or two-stage absorber system. With single-stage scrubbers, the flue gas reacts with an alkaline scrubber liquid to simultaneously remove HCl and SO_2. With two-stage scrubbers, a low-pH water scrubber for HCl removal is installed upstream of the alkaline SO_2 scrubber. The alkaline solution, typically containing calcium hydroxide [$Ca(OH)_2$], reacts with the acid gas to form salts, which are generally insoluble and may be removed by sequential clarifying, thickening, and vacuum filtering. The dewatered salts or sludges are then disposed.

2.1.4.6 Nitrogen Oxide Control Techniques -- The control of NO_x emissions can be accomplished through either combustion controls or add-on controls. Combustion controls include staged combustion, low excess air (LEA), and flue gas recirculation (FGR). Add-on controls which have been tested on MWCs include selective noncatalytic reduction (SNCR), selective catalytic reduction (SCR), and natural gas reburning.

Combustion controls involve the control of temperature or O_2 to reduce NO_x formation. With LEA, less air is supplied, which lowers the supply of O_2 that is available to react with N_2 in the combustion air. In staged combustion, the amount of underfire air is reduced, which generates a starved-air region. In FGR, cooled flue gas is mixed with combustion air, which reduces to O_2 content of the combustion air supply. Due to the lower combustion temperatures present in MWCs, most NO_x is produced from the oxidation of nitrogen present in the fuel. As a result, combustion modifications at MWCs have generally shown small to moderate reductions in NO_x emissions as compared to higher temperature combustion devices (i.e., fossil fuel-fired boilers).

With SNCR, ammonia (NH_3) or urea is injected into the furnace along with chemical additives to reduce NO_x to N_2 without the use of catalysts. Based on analyses of data from U.S. MWCs equipped with SNCR, NO_x reductions of 45 percent are achievable.

With SCR, NH_3 is injected into the flue gas downstream of the boiler where it mixes with NO_x in the flue gas and passes through a catalyst bed, where NO_x is reduced to N_2 by a reaction with NH_3. This technique has not been applied to U.S. MWCs, but has been used on MWCs in Japan and Germany. Reductions of up to 80 percent have been observed, but problems with catalyst poisoning and deactivation may reduce performance over time.

Natural gas reburning involves limiting combustion air produce an LEA zone. Recirculated flue gas and natural gas are then added to this LEA zone to produce a fuel-rich zone that inhibits NO_x formation and promotes reduction of NO_x to N_2. Natural gas reburning has been evaluated on both pilot- and full-scale applications and achieved NO_x reductions of 50 to 60 percent.

2.1.5 Mercury Controls[11-14]

Unlike other metals, Hg exists in vapor form at typical APCD operating temperatures. As a result, collection of Hg in the APCD is highly variable. Factors that affect Hg control are good PM control, low temperatures in the APCD system, and a sufficient level of carbon in the fly ash. Higher levels of carbon in the fly ash enhance Hg adsorption onto the PM, which is removed by the PM control device. To keep the Hg from volatilizing, it is important to operate the control systems at low temperatures, generally less than about 300 to 400°F.

Several mercury control technologies have been used on waste combustors in the United States, Canada, Europe, and Japan. These control technologies include the injection of activated carbon or sodium sulfide (Na_2S) into the flue gas prior to the DSI- or SD-based acid gas control system, or the use of activated carbon filters.

With activated carbon injection, Hg is adsorbed onto the carbon particle, which is then captured in the PM control device. Test programs using activated carbon injection on MWCs in the United States have shown Hg removal efficiencies of 50 to over 95 percent, depending on the carbon feed rate.

Sodium sulfide injection involves spraying Na_2S solution into cooled flue gas prior to the acid gas control device. Solid mercuric sulfide is precipitated from the reaction of Na_2S and Hg and can be collected in the PM control device. Results from tests on European and Canadian MWCs have shown removal efficiencies of 50 to over 90 percent. Testings on a U.S. MWC, however, raised questions on the effectiveness of this technology due to possible oversights in the analytical procedure used in Europe and Canada.

Fixed bed activated carbon filters are another Hg control technology being used in Europe. With this technology, the flue gas is passed through a fixed bed of granular activated carbon where the Hg is adsorbed. Segments of the bed are periodically replaced as system pressure drop increases.

2.1.6 Emissions[15-121]

Tables 2.1-1 through 2.1-9 present emission factors for MWCs. The tables are for distinct combustor types (i.e., MB/WW, RDF), and include emission factors for uncontrolled (prior to any pollution control device) levels and for controlled levels based on various APCD types (i.e., ESP, SD/FF). There are a large amount of data available for this source category, and as a result of this, many of the emission factors have high quality ratings. However, for some categories there were only limited data, and the ratings are low. In these cases, one should refer to the EPA Background Information Documents (BIDs) developed for the NSPS and EG, which more thoroughly analyze the data than does AP-42, as well as discuss performance capabilities of the control technologies and expected emission levels. Also, when using the MWC emission factors, it should be kept in mind that these are average values, and emissions from MWCs are greatly affected by the composition of the waste and may vary for different facilities due to seasonal and regional differences. The AP-42 background report for this section includes data for individual facilities that represent the range for a combustor/control technology category.

Table 2.1-1 (Metric Units). PARTICULATE MATTER, METALS, AND ACID GAS EMISSION FACTORS FOR MASS BURN AND MODULAR/EXCESS AIR COMBUSTORS[a,b]

(SCCs 50100104, 50100105, 50100106, 50100107, 50300111, 50300112, 50300113, 50300115)

	Uncontrolled		ESP[c]		DSI/ESP[d]		SD/ESP[e]		DSI/FF[f]		SD/FF[g]	
Pollutant	kg/Mg	Emission Factor Rating	kg/Mg	Emission Factor Rating	kg/Mg	Emission Factor Rating	kg/Mg	Emission Factor Rating	kg/Mg	Emission Factor Rating	kg/Mg	Emission Factor Rating
PM[h]	1.26E+01	A	1.05E-01	A	2.95E-02	E	3.52E-02	A	8.95E-02	A	3.11E-02	A
As[i]	2.14E-03	A	1.09E-05	A	ND[j]	E	6.85E-06	A	5.15E-06	C	2.12E-05	A
Cd[i]	5.45E-03	A	3.23E-04	B	4.44E-05	E	3.76E-06	A	1.17E-05	C	1.36E-05	A
Cr[i]	4.49E-03	A	5.65E-05	B	1.55E-05	E	1.30E-04	A	1.00E-04	C	1.50E-05	A
Hg[i]	2.8 E-03	A	2.8 E-03	A	1.98E-03	E	1.63E-03	A	1.10E-03	C	1.10E-03	A
Ni[i]	3.93E-03	A	5.60E-05	B	1.61E-03	E	1.35E-04	A	7.15E-05	C	2.58E-05	A
Pb[i]	1.07E-01	A	1.50E-03	A	1.45E-03	E	4.58E-04	A	1.49E-04	C	1.31E-04	A
SO_2	1.73E+00	A	---		4.76E-01	C	3.27E-01[k]	A	7.15E-01	C	2.77E-01[k]	A
HCl[i]	3.20E+00	A	---		1.39E-01	C	7.90E-02[k]	A	3.19E-01	C	1.06E-01[k]	A

a All factors in kg/Mg refuse combusted. Emission factors were calculated from concentrations using an F-factor of 9,570 dscf/MBtu and a heating value of 4,500 Btu/lb. Other heating values can be substituted by multiplying the emission factor by the new heating value and dividing by 4,500 Btu/lb. SCC = Source Classification Code.

b Emission factors should be used for estimating long-term, not short-term, emission levels. This particularly applies to pollutants measured with a continuous emission monitoring system (e.g., SO_2).

c ESP = Electrostatic Precipitator

d DSI/ESP = Duct Sorbent Injection/Electrostatic Precipitator

e SD/ESP = Spray Dryer/Electrostatic Precipitator

f DSI/FF = Duct Sorbent Injection/Fabric Filter

g SD/FF = Spray Dryer/Fabric Filter

h PM = total particulate matter, as measured with EPA Reference Method 5.

i Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

j ND = No data available at levels greater than detection limits.

k Acid gas emissions from SD/ESP- and SD/FF-equipped MWCs are essentially the same. Any differences are due to scatter in the data.

--- = Not available.

Table 2.1-2 (English Units). PARTICULATE MATTER, METALS, AND ACID GAS EMISSION FACTORS FOR MASS BURN AND MODULAR/EXCESS AIR COMBUSTORS[a,b]
(SCCs 50100104, 50100105, 50100106, 50100107, 50300111, 50300112, 50300113, 50300115)

	Uncontrolled		ESP[c]		DSI/ESP[d]		SD/ESP[e]		DSI/FF[f]		SD/FF[g]	
Pollutant	lb/ton	Emission Factor Rating	lb/ton	Emission Factor Rating	lb/ton	Emission Factor Rating	lb/ton	Emission Factor Rating	lb/ton	Emission Factor Rating	lb/ton	Emission Factor Rating
PM[h]	2.51E+01	A	2.10E-01	A	5.90E-02	E	7.03E-02	A	1.79E-01	A	6.20E-02	A
As[i]	4.37E-03	A	2.17E-05	A	ND[j]	E	1.37E-05	A	1.03E-05	C	4.23E-06	A
Cd[i]	1.09E-02	A	6.46E-04	B	8.87E-05	E	7.51E-05	A	2.34E-05	C	2.71E-05	A
Cr[i]	8.97E-03	A	1.13E-04	B	3.09E-05	E	2.59E-04	A	2.00E-04	C	3.00E-05	A
Hg[i]	5.6 E-03	A	5.6 E-03	A	3.96E-03	E	3.26E-03	A	2.20E-03	C	2.20E-03	A
Ni[i]	7.85E-03	A	1.12E-04	B	3.22E-05	E	2.70E-04	A	1.43E-04	C	5.16E-05	A
Pb[i]	2.13E-01	A	3.00E-03	A	2.90E-03	E	9.15E-04	A	2.97E-04	C	2.61E-04	A
SO_2	3.46E+00	A	---		9.51E-01	C	6.53E-01[k]	A	1.43E-00	C	5.54E-01[k]	A
HCl[i]	6.40E+00	A	---		2.78E-01	C	1.58E-01[k]	A	6.36E-01	C	2.11E-01[k]	A

a All factors in lb/ton refuse combusted. Emission factors were calculated from concentrations using an F-factor of 9,570 dscf/MBtu and a heating value of 4,500 Btu/lb. Other heating values can be substituted by multiplying the emission factor by the new heating value and dividing by 4,500 Btu/lb. SCC = Source Classification Code.

b Emission factors should be used for estimating long-term, not short-term, emission levels. This particularly applies to pollutants measured with a continuous emission monitoring system (e.g., SO_2).

c ESP = Electrostatic Precipitator

d DSI/ESP = Duct Sorbent Injection/Electrostatic Precipitator

e SD/ESP = Spray Dryer/Electrostatic Precipitator

f DSI/FF = Duct Sorbent Injection/Fabric Filter

g SD/FF = Spray Dryer/Fabric Filter

h PM = total particulate matter, as measured with EPA Reference Method 5.

i Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

j ND = No data available at levels greater than detection limits.

k Acid gas emissions from SD/ESP- and SD/FF-equipped MWCs are essentially the same. Any differences are due to scatter in the data.

--- = Not available.

Table 2.1-3 (Metric Units). ORGANIC, NITROGEN OXIDE, AND CARBON MONOXIDE EMISSION FACTORS FOR MASS BURN/WATERWALL COMBUSTORS[a,b]
(SCCs 50100105, 50300112)

Pollutant	Uncontrolled		ESP[c]		SD/ESP[d]		DSI/FF[d]		SD/FF[e]	
	kg/Mg	Emission Factor Rating	kg/Mg	Emission Factor Rating	kg/Mg	Emission Factor Rating	kg/Mg	Emission Factor Rating	kg/Mg	Emission Factor Rating
CDD/CDF[g]	8.35E-07	A	5.85E-07	A	3.11E-07	A	8.0E-08	C	3.31E-08	A
NO_X[h]	1.83E+00	A	*		*		*		*	
CO[h]	2.32E-01	A	*		*		*		*	

a All factors in kg/Mg refuse combusted. Emission factors were calculated from concentrations using an F-factor of 9,570 dscf/MBtu and a heating value of 4,500 Btu/lb. Other heating values can be substituted by multiplying the emission factor by the new heating value and dividing by 4,500 Btu/lb. SCC = Source Classification Code.

b Emission factors should be used for estimating long-term, not short-term, emission levels. This particularly applies to pollutants measured with a continuous emission monitoring system (e.g., CO, NO_X).

c ESP = Electrostatic Precipitator

d SD/ESP = Spray Dryer/Electrostatic Precipitator

e DSI/FF = Duct Sorbent Injection/Fabric Filter

f SD/FF = Spray Dryer/Fabric Filter

g CDD/CDF = total tetra-through octa-chlorinated dibenzo-p-dioxin/chlorinated dibenzofurans, 2,3,7,8-tetrachlorodibenzo-p-dioxin and dibenzofurans are Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

h Control of NO_X and CO is not tied to traditional acid gas/PM control devices.

* = Same as "uncontrolled" for these pollutants.

Table 2.1-4 (English Units). ORGANIC, NITROGEN OXIDE, AND CARBON MONOXIDE EMISSION FACTORS FOR MASS BURN/WATERWALL COMBUSTORS[a,b]
(SCCs 50100105, 50300112)

Pollutant	Uncontrolled		ESP[c]		SD/ESP[d]		DSI/FF[e]		SD/FF[f]	
	lb/ton	Emission Factor Rating	lb/ton	Emission Factor Rating	lb/ton	Emission Factor Rating	lb/ton	Emission Factor Rating	lb/ton	Emission Factor Rating
CDD/CDF[g]	1.67E-06	A	1.17E-06	A	6.21E-07	A	1.60E-07	C	6.61E-08	A
NO_x[h]	3.56E+00	A	*		*		*		*	
CO[h]	4.63E-01	A	*		*		*		*	

a All factors in lb/ton refuse combusted. Emission factors were calculated from concentrations using an F-factor of 9,570 dscf/MBtu and a heating value of 4,500 Btu/lb. Other heating values can be substituted by multiplying the emission factor by the new heating value and dividing by 4,500 Btu/lb. SCC = Source Classification Code.

b Emission factors should be used for estimating long-term, not short-term, emission levels. This particularly applies to pollutants measured with a continuous emission monitoring system (e.g., CO, NO_x).

c ESP = Electrostatic Precipitator

d SD/ESP = Spray Dryer/Electrostatic Precipitator

e DSI/FF = Duct Sorbent Injection/Fabric Filter

f SD/FF = Spray Dryer/Fabric Filter

g CDD/CDF = total tetra-through octa-chlorinated dibenzo-p-dioxin/chlorinated dibenzofurans, 2,3,7,8-tetrachlorodibenzo-p-dioxin and dibenzofurans are Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

h Control of NO_x and CO is not tied to traditional acid gas/PM control devices.

* = Same as "uncontrolled" for these pollutants.

Table 2.1-5 (Metric and English Units). ORGANIC, NITROGEN OXIDE, AND CARBON MONOXIDE EMISSION FACTORS FOR MASS BURN/ROTARY WATERWALL COMBUSTORS[a,b]
(SCCs 50100106, 50300113)

Pollutant	Uncontrolled			ESP[c]			DSI/FF[d]			SD/FF[e]		
	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating
CDD/CDF[f]	---	---		---	---		4.58E-08	9.16E-08	D	2.66E-08	5.31E-08	B
NO_X[g]	1.13E+00	2.25E+00	E	*	*		*	*		*	*	
CO[g]	3.83E-01	7.66E-01	C	*	*		*	*		*	*	

a Emission factors were calculated from concentrations using an F-factor of 9,570 dscf/MBtu and a heating value of 4,500 Btu/lb. Other heating values can be substituted by multiplying the emission factor by the new heating value and dividing by 4,500 Btu/lb. SCC = Source Classification Code.

b Emission factors should be used for estimating long-term, not short-term, emission levels. This particularly applies to pollutants measured with a continuous emission monitoring system (e.g., CO, NO_X).

c ESP = Electrostatic Precipitator

d DSI/FF = Duct Sorbent Injection/Fabric Filter

e SD/FF = Spray Dryer/Fabric Filter

f CDD/CDF = total tetra-through octa-chlorinated dibenzo-p-dioxin/chlorinated dibenzofurans, 2,3,7,8-tetrachlorodibenzo-p-dioxin and dibenzofurans are Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

g Control of NO_X and CO is not tied to traditional acid gas/PM control devices.

--- = Not available.

* = Same as "uncontrolled" for these pollutants.

Table 2.1-6 (Metric and English Units). ORGANIC, NITROGEN OXIDE, AND CARBON MONOXIDE EMISSION FACTORS FOR MASS BURN/REFRACTORY WALL COMBUSTORS[a,b]
(SCCs 50100104, 50300111)

Pollutant	Uncontrolled			ESP[c]			DSI/ESP[d]		
	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating
CDD/CDF[e]	7.50E-06	1.50E-05	D	3.63E-05	7.25E-05	D	2.31E-07	4.61E-07	E
NO_x[f]	1.23E+00	2.46E+00	A	*	*		*	*	
CO[f]	6.85E-01	1.37E+00	C	*	*		*	*	

a Emission factors were calculated from concentrations using an F-factor of 9,570 dscf/MBtu and a heating value of 4,500 Btu/lb. Other heating values can be substituted by multiplying the emission factor by the new heating value and dividing by 4,500 Btu/lb. SCC = Source Classification Code.

b Emission factors should be used for estimating long-term, not short-term, emission levels. This particularly applies to pollutants measured with a continuous emission monitoring system (e.g., CO, NO_x).

c ESP = Electrostatic Precipitator

d DSI/ESP = Duct Sorbent Injection/Electrostatic Precipitator

e CDD/CDF = total tetra-through octa-chlorinated dibenzo-p-dioxin/chlorinated dibenzofurans, 2,3,7,8-tetrachlorodibenzo-p-dioxin and dibenzofurans are Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

f Control of NO_x and CO is not tied to traditional acid gas/PM control devices.

* = Same as "uncontrolled" for these pollutants.

Table 2.1-7 (Metric and English Units). ORGANIC, NITROGEN OXIDE, AND CARBON MONOXIDE EMISSION FACTORS FOR MODULAR/EXCESS AIR COMBUSTORS[a,b]
(SCCs 50100107, 50300115)

Pollutant	Uncontrolled			ESP[c]			DSI/FF[d]		
	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating
CDD/CDF[e]	---	---		1.11E-06	2.22E-06	C	3.12E-08	6.23E-08	E
NO_X[f]	1.24E+00	2.47E+00	A	*	*		*	*	
CO[f]	---	---		*	*		*	*	

a Emission factors were calculated from concentrations using an F-factor of 9,570 dscf/MBtu and a heating value of 4,500 Btu/lb. Other heating values can be substituted by multiplying the emission factor by the new heating value and dividing by 4,500 Btu/lb. SCC = Source Classification Code.

b Emission factors should be used for estimating long-term, not short-term, emission levels. This particularly applies to pollutants measured with a continuous emission monitoring system (e.g., CO, NO_X).

c ESP = Electrostatic Precipitator

d DSI/FF = Duct Sorbent Injection/Fabric Filter

e CDD/CDF = total tetra-through octa-chlorinated dibenzo-p-dioxin/chlorinated dibenzofurans, 2,3,7,8-tetrachlorodibenzo-p-dioxin and dibenzofurans are Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

f Control of NO_X and CO is not tied to traditional acid gas/PM control devices.

--- = Not available.

* = Same as "uncontrolled" for these pollutants.

Table 2.1-8 (Metric and English Units). EMISSION FACTORS FOR REFUSE-DERIVED FUEL-FIRED COMBUSTORS[a,b]
(SCCs 50100103)

Pollutant	Uncontrolled			ESP[c]			SD/ESP[d]			SD/FF[e]		
	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating
PM[f]	3.48E+01	6.96E+01	A	5.17E-01	1.04E+00	A	4.82E-02	9.65E-02	B	6.64E-02	1.33E-01	B
As[g]	2.97E-03	5.94E-03	B	6.70E-05	1.34E-04	D	5.41E-06	1.08E-05	D	2.59E-06[h]	5.17E-06[h]	A
Cd[g]	4.37E-03	8.75E-03	C	1.10E-04	2.20E-04	C	4.18E-05	8.37E-05	D	1.66E-05[h]	3.32E-05[h]	A
Cr[g]	6.99E-03	1.40E-02	B	2.34E-04	4.68E-04	D	5.44E-05	1.09E-04	D	2.04E-05	4.07E-05	D
Hg[g]	2.8 E-03	5.5 E-03	D	2.8 E-03	5.5 E-03	D	2.10E-04	4.20E-04	B	1.46E-04	2.92E-04	D
Ni[g]	2.18E-03	4.36E-03	C	9.05E-03	1.81E-02	D	9.64E-05	1.93E-04	D	3.15E-05[i]	6.30E-05[i]	A
Pb[g]	1.00E-01	2.01E-01	C	1.84E-03[h]	3.66E-03[h]	A	5.77E-04	1.16E-03	B	5.19E-04	1.04E-03	D
SO_2	1.95E+00	3.90E+00	C	---	---		7.99E-01	1.60E+00	D	2.21E-01	4.41E-01	D
HCl[g]	3.49E+00	6.97E+00	E	*	*		---	---		2.64E-02	5.28E-02	C
NO_x[j]	2.51E+00	5.02E+00	A	*	*		*	*		*	*	
CO[j]	9.60E-01	1.92E+00	A	*	*		*	*		*	*	
CDD/CDF[k]	4.73E-06	9.47E-06	D	8.46E-06	1.69E-05	B	5.31E-03	1.06E-07	D	1.22E-08	2.44E-08	E

a Emission factors were calculated from concentrations using an F-factor of 9,570 dscf/MBtu and a heating value of 5,500 Btu/lb. Other heating values can be substituted by multiplying the emission factor by the new heating value and dividing by 5,500 Btu/lb. SCC = Source Classification Code.

b Emission factors should be used for estimating long-term, not short-term, emission levels. This particularly applies to pollutants measured with a continuous emission monitoring system (SO_2, NO_x, CO).

c ESP = Electrostatic Precipitator

d SD/ESP = Spray Dryer/Electrostatic Precipitator

e SD/FF = Spray Dryer/Fabric Filter

f PM = total particulate matter, as measured with EPA Reference Method 5.

g Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

h Levels were measured at non-detect levels, where the detection limit was higher than levels measured at other similarly equipped MWCs. Emission factors shown are based on emission levels from similarly equipped mass burn and MOD/EA combustors.

i No data available. Values shown are based on emission levels from SD/FF-equipped mass burn combustors.

j Control of NO_x and CO is not tied to traditional acid gas/PM control devices.

k CDD/CDF = total tetra-through octa-chlorinated dibenzo-p-dioxin/chlorinated dibenzofurans, 2,3,7,8-tetrachlorodibenzo-p-dioxin and dibenzofurans are Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

-- = Not available

* = Same as uncontrolled for these pollutants.

Table 2.1-9 (Metric and English Units). EMISSION FACTORS FOR MODULAR STARVED AIR COMBUSTORS[a,b] (SCCs 50100101, 50300114)

Pollutant	Uncontrolled			ESP[c]		
	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating
PM[d]	1.72E+00	3.43E+00	B	1.74E-01	3.48E-01	B
As[e]	3.34E-04	6.69E-04	C	5.25E-05	1.05E-04	D
Cd[e]	1.20E-03	2.41E-03	D	2.30E-04	4.59E-04	D
Cr[e]	1.65E-03	3.31E-03	C	3.08E-04	6.16E-04	D
Hg[e,f]	2.8 E-03	5.6 E-03	A	2.8 E-03	5.6 E-03	A
Ni[e]	2.76E-03	5.52E-03	D	5.04E-04	1.01E-03	E
Pb[e]	---	---		1.41E-03	2.82E-03	C
SO_2	1.61E+00	3.23E+00	E	*	*	
HCl[e]	1.08E+00	2.15E+00	D	*	*	
NO_x[g]	1.58E+00	3.16E+00	B	*	*	
CO[g]	1.50E-01	2.99E-01	B	*	*	
CDD/CDF[h]	1.47E-06	2.94E-06	D	1.88E-06	3.76E-06	C

a Emission factors were calculated from concentrations using an F-factor of 9,570 dscf/MBtu and a heating value of 4,500 Btu/lb. Other heating values can be substituted by multiplying the emission factor by the new heating value and dividing by 4,500 Btu/lb. SCC = Source Classification Code.

b Emission factors should be used for estimating long-term, not short-term, emission levels. This particularly applies to pollutants measured with a continuous emission monitoring system (e.g., CO, NO_x).

c ESP = Electrostatic Precipitator

d PM = total particulate matter, as measured with EPA Reference Method 5.

e Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

f Mercury levels based on emission levels measured at mass burn, MOD/EA, and MOD/SA combustors.

g Control of NO_x and CO is not tied to traditional acid gas/PM control devices.

h CDD/CDF = total tetra-through octa-chlorinated dibenzo-p-dioxin/chlorinated dibenzofurans, 2,3,7,8-tetrachlorodibenzo-p-dioxin and dibenzofurans are Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

* = Same as "uncontrolled" for these pollutants.

--- = Not available

Another point to keep in mind when using emission factors is that certain control technologies, specifically ESPs and DSI systems, are not all designed with equal performance capabilities. The ESP and DSI-based emission factors are based on data from a variety of facilities and represent average emission levels for MWCs equipped with these control technologies. To estimate emissions for a specific ESP or DSI system, refer to either the AP-42 background report for this section or the NSPS and EG BIDs to obtain actual emissions data for these facilities. These documents should also be used when conducting risk assessments, as well as for determining removal efficiencies. Since the AP-42 emission factors represent averages from numerous facilities, the uncontrolled and controlled levels frequently do not correspond to simultaneous testing and should not be used to calculate removal efficiencies.

Emission factors for MWCs were calculated from flue gas concentrations using an F-factor of 9,570 dry standard cubic feet per million British thermal unit (Btu) and an assumed heating value of the waste of 4,500 Btu per pound (Btu/lb) for all combustors except RDF, for which a 5,500 Btu/lb heating value was assumed. These are average values for MWCs, however, a particular facility may have a different heating value for the waste. In such a case, the emission factors shown in the tables can be adjusted by multiplying the emission factor by the actual facility heating value and dividing by the assumed heating value (4,500 or 5,500 Btu/lb, depending on the combustor type). Also, conversion factors to obtain concentrations, which can be used for developing more specific emission factors or make comparisons to regulatory limits, are provided in Tables 2.1-10 and 2.1-11 for all combustor types (except RDF) and RDF combustors, respectively.

Also note that the values shown in the tables for PM are for total PM, and the CDD/CDF data represent total tetra- through octa-CDD/CDF. For SO_2, NO_x, and CO, the data presented in the tables represent long-term averages, and should not be used to estimate short-term emissions. Refer to the EPA BIDs which discuss achievable emission levels of SO_2, NO_x, and CO for different averaging times based on analysis of continuous emission monitoring data. Lastly, for PM and metals, levels for MB/WW, MB/RC, MB/REF, and MOD/EA were combined to determine the emission factors, since these emissions should be the same for these types of combustors. For controlled levels, data were combined within each control technology type (e.g., SD/FF data, ESP data). For Hg, MOD/SA data were also combined with the mass burn and MOD/EA data.

2.1.7 Other Types Of Combustors[122-134]

Industrial/commercial Combustors - The capacities of these units cover a wide range, generally between 23 and 1,800 kilograms (50 and 4,000 pounds) per hour. Of either single- or multiple-chamber design, these units are often manually charged and intermittently operated. Some industrial combustors are similar to municipal combustors in size and design. Emission control systems include gas-fired afterburners, scrubbers, or both. Under Section 129 of the CAAA, these types of combustors will be required to meet emission limits for the same list of pollutants as for MWCs. The EPA has not yet established these limits.

Trench Combustors - Trench combustors, also called air curtain incinerators, forcefully project a curtain of air across a pit in which open burning occurs. The air curtain is intended to increase combustion efficiency and reduce smoke and PM emissions. Underfire air is also used to increase combustion efficiency.

Table 2.1-10. CONVERSION FACTORS FOR ALL COMBUSTOR TYPES EXCEPT RDF

Divide	By	To Obtain*
For As, Cd, Cr, Hg, Ni, Pb, and CDD/CDF:		
kg/Mg refuse	4.03×10^{-6}	μg/dscm
lb/ton refuse	8.06×10^{-6}	
For PM:		
kg/Mg refuse	4.03×10^{-3}	mg/dscm
lb/ton refuse	8.06×10^{-3}	
For HCl:		
kg/Mg refuse	6.15×10^{-3}	ppmv
lb/ton refuse	1.23×10^{-2}	
For SO_2:		
kg/Mg refuse	1.07×10^{-2}	ppmv
lb/ton refuse	2.15×10^{-2}	
For NO_x:		
kg/Mg refuse	7.70×10^{-3}	ppmv
lb/ton refuse	1.54×10^{-2}	
For CO:		
kg/Mg refuse	4.69×10^{-3}	ppmv
lb/ton refuse	9.4×10^{-3}	

*at 7 percent O_2.

Table 2.1-11. CONVERSION FACTORS FOR REFUSE-DERIVED FUEL COMBUSTORS

Divide	By	To Obtain*
For As, Cd, Cr, Hg, Ni, Pb, and CDD/CDF:		
kg/Mg refuse	4.92×10^{-6}	μg/dscm
lb/ton refuse	9.85×10^{-6}	
For PM:		
kg/Mg refuse	4.92×10^{-3}	mg/dscm
lb/ton refuse	9.85×10^{-3}	
For HCl:		
kg/Mg refuse	7.5×10^{-3}	ppmv
lb/ton refuse	1.5×10^{-2}	
For SO_2:		
kg/Mg refuse	1.31×10^{-2}	ppmv
lb/ton refuse	2.62×10^{-2}	
For NO_x:		
kg/Mg refuse	9.45×10^{-3}	ppmv
lb/ton refuse	1.89×10^{-2}	
For CO:		
kg/Mg refuse	5.75×10^{-3}	ppmv
lb/ton refuse	1.15×10^{-2}	

*at 7 percent O_2.

Trench combustors can be built either above- or below-ground. They have refractory walls and floors and are normally 8-feet wide and 10-feet deep. Length varies from 8 to 16 feet. Some units have mesh screens to contain larger particles of fly ash, but other add-on pollution controls are normally not used.

Trench combustors burning wood wastes, yard wastes, and clean lumber are exempt from Section 129, provided they comply with opacity limitations established by the Administrator. The primary use of air curtain incinerators is the disposal of these types of wastes, however, some of these combustors are used to burn MSW or construction and demolition debris.

In some states, trench combustors are often viewed as a version of open burning and the use of these types of units has been discontinued in some States.

Domestic Combustors - This category includes combustors marketed for residential use. These types of units are typically located at apartment complexes, residential buildings, or other multiple family dwellings, and are generally found in urban areas. Fairly simple in design, they may have single or multiple refractory-lined chambers and usually are equipped with an auxiliary burner to aid combustion. Due to their small size, these types of units are not currently covered by the MWC regulations.

Flue-fed Combustors - These units, commonly found in large apartment houses or other multiple family dwellings, are characterized by the charging method of dropping refuse down the combustor flue and into the combustion chamber. Modified flue-fed incinerators utilize afterburners and draft controls to improve combustion efficiency and reduce emissions. Due to their small size, these types of units are not currently covered by the MWC regulations.

Emission factors for industrial/commercial, trench, domestic, and flue fed combustors are presented in Table 2.1-12.

Table 2.1-12 (Metric and English Units). UNCONTROLLED EMISSION FACTORS FOR REFUSE COMBUSTORS OTHER THAN MUNICIPAL WASTE[a]

EMISSION FACTOR RATING: D

Combustor Type	PM		SO_2		CO		Total Organic Compounds[b]		NO_x	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
Industrial/Commercial										
Multiple Chamber	3.50E+00	7.00E+00	1.25E+00	2.50E+00	5.00E+00	1.00E+01	1.50E+00	3.00E+00	1.50E+00	3.00E+00
Single Chamber	7.50E+00	1.50E+01	1.25E+00	2.50E+00	1.00E+01	2.00E+01	7.50E+01	1.50E+01	1.00E+00	2.00E+00
Trench										
Wood (50100510, 50300106)	6.50E+00	1.30E+01	5.00E-02	1.00E-01	---	---	---	---	2.00E+00	4.00E+00
Rubber tires (50100511, 50300107)	6.90E+01	1.38E+02	---	---	---	---	---	---	---	---
Municipal refuse (50100512, 50300109)	1.85E+01	3.70E+01	1.25E+00	2.50E+00	---	---	---	---	---	---
Flue-fed single chamber	1.50E+01	3.00E+01	2.50E-01	5.00E-01	1.00E+01	2.00E+01	7.50E+00	1.50E+01	1.50E+00	3.00E+00
Flue-fed (modified)	3.00E+00	6.00E+00	2.50E-01	5.00E-01	5.00E+00	1.00E+01	1.50E+00	3.00E+00	5.00E+00	1.00E+01
Domestic single chamber (no SCC)										
Without primary burner	1.75E+01	3.50E+01	2.50E-01	5.00E-01	1.50E+02	3.00E+02	5.00E+01	1.00E+02	5.00E-01	1.00E+00
With primary burner	3.50E+00	7.00E+00	2.50E-01	5.00E-01	Neg[c]	Neg[c]	1.00E+00	2.00E+00	1.00E+00	2.00E+00

[a] References 116-123.
[b] Expressed as methane.
[c] Neg = negligible.
--- = Not available.

References for Section 2.1

1. Memorandum from D. A. Fenn, and K. L. Nebel, Radian Corporation, Research Triangle Park, NC, to W. H. Stevenson, U. S. Environmental Protection Agency, Research Triangle Park, NC. March 1992.

2. J. Kiser, "The Future Role of Municipal Waste Combustion," *Waste Age*, November 1991,

3. September 6, 1991. Meeting Summary: Appendix 1 (Docket No. A-90-45, Item Number II-E-12).

4. *Municipal Waste Combustion Study: Combustion Control of Organic Emissions*, EPA/530-SW-87-021c, U. S. Environmental Protection Agency, Washington, DC, June 1987.

5. M. Clark, "Minimizing Emissions from Resource Recovery," Presented at the International Workshop on Municipal Waste Incineration, Quebec, Canada, October 1-2, 1987.

6. *Municipal Waste Combustion Assessment: Combustion Control at Existing Facilities*, EPA 600/8-89-058, U. S. Environmental Protection Agency, Research Triangle Park, NC, August 1989.

7. *Municipal Waste Combustors - Background Information for Proposed Standards: Control of NO_x Emissions*, EPA-450/3-89-27d, U. S. Environmental Protection Agency, Research Triangle Park, NC, August 1989.

8. *Municipal Waste Combustors - Background Information for Proposed Standards: Post Combustion Technology Performance*, U. S. Environmental Protection Agency, August 1989.

9. *Municipal Waste Combustion Study - Flue Gas Cleaning Technology*, EPA/530-SW-87-021c, U. S. Environmental Protection Agency, Washington, DC, June 1987.

10. R. Bijetina, *et al.*, "Field Evaluation of Methane de-NO_x at Olmstead Waste-to-Energy Facility," Presented at the 7th Annual Waste-to-Energy Symposium, Minneapolis, MN, January 28-30, 1992.

11. K. L. Nebel and D. M. White, *A Summary of Mercury Emissions and Applicable Control Technologies for Municipal Waste Combustors*, Research Triangle Park, NC, September, 1991.

12. *Emission Test Report: OMSS Field Test on Carbon Injection for Mercury Control*, EPA-600/R-92-192, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1992.

13. J. D. Kilgroe, *et al.*, "Camden Country MWC Carbon Injection Test Results," Presented at the International Conference on Waste Combustion, Williamsburg, VA, March 1993.

14. Meeting Summary: *Preliminary Mercury Testing Results for the Stanislaus County Municipal Waste Combustor*, U. S. Environmental Protection Agency, Research Triangle Park, NC, November 22, 1991.

15. R. A. Zurlinden, *et al.*, *Environmental Test Report, Alexandria/Arlington Resources Recovery Facility, Units 1, 2, and 3*, Report No. 144B, Ogden Martin Systems of Alexandria/Arlington, Inc., Alexandria, VA, March 9, 1988.

16. R. A. Zurlinden, *et al.*, *Environmental Test Report, Alexandria/Arlington Resource Recovery Facility, Units 1, 2, and 3*, Report No. 144A (Revised), Ogden Martin Systems of Alexandria/Arlington, Inc., Alexandria, VA, January 8, 1988.

17. *Environmental Test Report, Babylon Resource Recovery Test Facility, Units 1 and 2*, Ogden Martin Systems of Babylon, Inc., Ogden Projects, Inc., March 1989.

18. Ogden Projects, Inc. *Environmental Test Report, Units 1 and 2, Babylon Resource Recovery Facility*, Ogden Martin Systems for Babylon, Inc., Babylon, NY, February 1990.

19. PEI Associates, Inc. *Method Development and Testing for Chromium, No. Refuse-to-Energy Incinerator, Baltimore RESCO*, EMB Report 85-CHM8, EPA Contract No. 68-02-3849, U. S. Environmental Protection Agency, Research Triangle Park, NC, August 1986.

20. Entropy Environmentalists, Inc. *Particulate, Sulfur Dioxide, Nitrogen Oxides, Chlorides, Fluorides, and Carbon Monoxide Compliance Testing, Units 1, 2, and 3*, Baltimore RESCO Company, L. P., Southwest Resource Recovery Facility, RUST International, Inc., January 1985.

21. Memorandum. J. Perez, AM/3, State of Wisconsin, to Files. "Review of Stack Test Performed at Barron County Incinerator," February 24, 1987.

22. D. S. Beachler, *et al.*, "Bay County, Florida, Waste-to-Energy Facility Air Emission Tests. Westinghouse Electric Corporation", Presented at Municipal Waste Incineration Workshop, Montreal, Canada, October 1987.

23. *Municipal Waste Combustion, Multi-Pollutant Study. Emission Test Report. Volume I, Summary of Results*, EPA-600/8-89-064a, Maine Energy Recovery Company, Refuse-Derived Fuel Facility, Biddeford, ME, July 1989.

24. S. Klamm, *et al.*, *Emission Testing at an RDF Municipal Waste Combustor*, EPA Contract No. 68-02-4453, U. S. Environmental Protection Agency, NC, May 6, 1988. (Biddeford)

25. *Emission Source Test Report -- Preliminary Test Report on Cattaraugus County*, New York State Department of Environmental Conservation, August 5, 1986.

26. *Permit No. 0560-0196 for Foster Wheeler Charleston Resource Recovery, Inc. Municipal Solid Waste Incinerators A & B*, Bureau of Air Quality Control, South Carolina Department of Health and Environmental Control, Charleston, SC, October 1989.

27. Almega Corporation. *Unit 1 and Unit 2, EPA Stack Emission Compliance Tests, May 26, 27, and 29, 1987, at the Signal Environmental Systems, Claremont, NH, NH/VT Solid Waste Facility*, Prepared for Clark-Kenith, Inc. Atlanta, GA, July 1987.

28. Entropy Environmentalists, Inc. *Stationary Source Sampling Report, Signal Environmental Systems, Inc., at th eClaremont Facility, Claremont, New Hampshire, Dioxins/Furans Emissions Compliance Testing, Units 1 and 2*, Reference No. 5553-A, Signal Environmental Systems, Inc., Claremont, NH, October 2, 1987.

29. M. D. McDannel, *et al., Air Emissions Tests at Commerce Refuse-to-Energy Facility May 26 - June 5, 1987*, County Sanitation Districts of Los Angeles County, Whittier, CA, July 1987.

30. M. D. McDannel and B. L. McDonald, *Combustion Optimization Study at the Commerce Refuse-to-Energy Facility. Volume I*, ESA 20528-557, County Sanitation Districts of Los Angeles County, Los Angeles, CA, June 1988.

31. M. D. McDannel *et al., Results of Air Emission Test During the Waste-to-Energy Facility*, County Sanitation Districts of Los Angeles County, Whittier, CA, December 1988. (Commerce)

32. Radian Corporation. *Preliminary Data from October - November 1988 Testing at the Montgomery County South Plant, Dayton, Ohio.*

33. Telefax. M. Hartman, Combustion Engineering to D. White, Radian Corporation. Detroit Compliance Tests, September 1990.

34. Interpoll Laboratories. *Results of the November 3-6, 1987 Performance Test on the No. 2 RDF and Sludge Incinerator at the WLSSD Plant in Duluth, Minnesota*, Interpoll Report No. 7-2443, April 25, 1988.

35. D. S. Beachler, (Westinghouse Electric Corporation) and ETS, Inc, *Dutchess County Resource Recovery Facility Emission Compliance Test Report, Volumes 1-5*, New York Department of Environmental Conservation, June 1989.

36. ETS, Inc. *Compliance Test Report for Dutchess County Resource Recovery Facility*, May 1989.

37. Letter and enclosures from W. Harold Snead, City of Galax, VA, to Jack R. Farmer, U. S. Environmental Protection Agency, Research Triangle Park, NC, July 14, 1988.

38. Cooper Engineers, Inc., *Air Emissions Tests of Solid Waste Combustion a Rotary Combustion/Boiler System at Gallatin, Tennessee*, West County Agency of Contra Costa County, CA, July 1984.

39. B. L. McDonald, *et al., Air Emissions Tests at the Hampton Refuse-Fired Stream Generating Facility, April 18-24, 1988*, Clark-Kenith, Incorporated, Bethesda, MD, June 1988.

40. Radian Corporation for American Ref-Fuel Company of Hempstead, *Compliance Test Report for the Hempstead Resource Recovery Facility, Westbury, NY*, Volume I, December 1989.

41. J. Campbell, Chief, Air Engineering Section, Hillsborough County Environmental Protection Commission, to E. L. Martinez, Source Analysis Section/AMTB, U. S. Environmental Protection Agency, May 1, 1986.

42. Mitsubishi SCR System for Municipal Refuse Incinerator, *Measuring Results at Tokyo-Hikarigaoka and Iwatsuki*, Mitsubishi Heavy Industries, Ltd, July 1987.

43. Entropy Environmentalists, Inc. for Honolulu Resource Recovery Venture, *Stationary Source Sampling Final Report*, Volume I, Oahu, HI, February 1990.

44. Ogden Projects, Inc., *Environmental Test Report, Indianapolis Resource Recovery Facility, Appendix A and Appendix B, Volume I*, (Prepared for Ogden Martin Systems of Indianapolis, Inc.), August 1989.

45. Knisley, D.R., et al. (Radian Corporation), *Emissions Test Report, Dioxin/Furan Emission Testing, Refuse Fuels Associates, Lawrence MA*, (Prepared for Refuse Fuels Association), Haverhill, MA, June 1987.

46. Entropy Environmentalists, Inc. *Stationary Source Sampling Report, Ogden Martin Systems of Haverhill, Inc., Lawrence, MA Thermal Conversion Facility. Particulate, Dioxins/Furans and Nitrogen Oxides Emission Compliance Testing*, September 1987.

47. Ethier, D.D., L.N. Hottenstein, and E.A. Pearson (TRC Environmental Consultants), *Air Emission Test Results at the Southeast Resource Recovery Facility Unit 1, October - December, 1988*, Prepared for Dravo Corporation, Long Beach, CA. February 28, 1989.

48. Letter from Rigo, H.G., Rigo & Rigo Associates, Inc., to Johnston, M., U. S. Environmental Protection Agency. March 13, 1989. 2 pp. Compliance Test Report Unit No. 1 -- South East Resource Recovery Facility, Long Beach, CA.

49. Vancil, M.A. and C.L. Anderson (Radian Corporation), *Summary Report CDD/CDF, Metals, HCl, SO_2, NO_x, CO and Particulate Testing, Marion County Solid Waste-to-Energy Facility, Inc., Ogden Martin Systems of Marion, Brooks, Oregon*, U. S. Environmental Protection Agency, Research Triangle Park, NC, EMB Report No. 86-MIN-03A, September 1988.

50. Anderson, C.L., et al. (Radian Corporation), *Characterization Test Report, Marion County Solid Waste-to-Energy Facility, Inc., Ogden Martin Systems of Marion, Brooks, Oregon*, U. S. Environmental Protection Agency, Research Triangle Park, NC, EMB Report No. 86-MIN-04, September 1988.

51. Letter Report from M.A. Vancil, Radian Corporation, to C.E. Riley, EMB Task Manager, U. S. Environmental Protection Agency. Emission Test Results for the PCDD/PCDF Internal Standards Recovery Study Field Test: Runs 1, 2, 3, 5, 13, 14. July 24, 1987. (Marion)

52. Anderson, C.L., K.L. Wertz, M.A. Vancil, and J.W. Mayhew (Radian Corporation). *Shutdown/Startup Test Program Emission Test Report, Marion County Solid Waste-to-Energy Facility, Inc., Ogden Martin Systems of Marion, Brooks, Oregon*, U. S. Environmental Protection Agency, Research Triangle Park, NC, EMB Report No. 87-MIN-4A, September 1988.

53. Clean Air Engineering, Inc., *Report on Compliance Testing for Waste Management, Inc. at the McKay Bay Refuse-to-Energy Project located in Tampa, Florida*, October 1985.

54. Alliance Technologies Corporation, *Field Test Report - NITEP III. Mid-Connecticut Facility, Hartford, Connecticut. Volume II Appendices*, Prepared for Environment Canada. June 1989.

55. Anderson, C.L. (Radian Corporation), *CDD/CDF, Metals, and Particulate Emissions Summary Report, Mid-Connecticut Resource Recovery Facility, Hartford, Connecticut*, U. S. Environmental Protection Agency, Research Triangle Park, NC, EMB Report No. 88-MIN-09A, January 1989.

56. Entropy Environmentalists, Inc., *Municipal Waste Combustion Multi-Pollutant Study, Summary Report, Wheelabrator Millbury, Inc., Millbury, MA*, U. S. Environmental Protection Agency, Research Triangle Park, NC, EMB Report No. 88-MIN-07A, February 1989.

57. Entropy Environmentalists, Inc., *Emissions Testing Report, Wheelabrator Millbury, Inc. Resource Recovery Facility, Millbury, Massachusetts, Unit Nos. 1 and 2, February 8 through 12, 1988*, Prepared for Rust International Corporation. Reference No. 5605-B. August 5, 1988.

58. Entropy Environmentalists, Inc., *Stationary Source Sampling Report, Wheelabrator Millbury, Inc., Resource Recovery Facility, Millbury, Massachusetts, Mercury Emissions Compliance Testing, Unit No. 1, May 10 and 11, 1988*, Prepared for Rust International Corporation. Reference No. 5892-A. May 18, 1988.

59. Entropy Environmentalists, Inc., *Emission Test Report, Municipal Waste Combustion Continuous Emission Monitoring Program, Wheelabrator Resource Recovery Facility, Millbury, Massachusetts*, U. S. Environmental Protection Agency, Research Triangle Park, NC, Emission Test Report 88-MIN-07C, January 1989.

60. Entropy Environmentalist, *Municipal Waste Combustion Multipollutant Study: Emission Test Report - Wheelabrator Millbury, Inc. Millbury, Massachusetts*, EMB Report No. 88-MIN-07, July 1988.

61. Entropy Environmentalists, *Emission Test Report, Municipal Waste Combustion, Continuous Emission Monitoring Program, Wheelabrator Resource Recovery Facility, Millbury, Massachusetts*, Prepared for the U. S. Environmental Protection Agency, Research Triangle Park, NC. EPA Contract No. 68-02-4336. October 1988.

62. Entropy Environmentalists, *Emissions Testing at Wheelabrator Millbury, Inc. Resource Recovery Facility, Millbury, Massachusetts*, Prepared for Rust International Corporation. February 8-12, 1988.

63. Radian Corporation, *Site-Specific Test Plan and Quality Assurance Project Plan for the Screening and Parametric Programs at the Montgomery County Solid Waste Management Division South Incinerator - Unit #3*, Prepared for U. S. EPA, OAQPS and ORD, Research Triangle Park, NC. November 1988.

64. Letter and enclosures from John W. Norton, County of Montgomery, OH, to Jack R. Farmer, U. S. Environmental Protection Agency, Research Triangle Park, NC. May 31, 1988.

65. Hahn, J.L., et al., (Cooper Engineers) and J.A. Finney, Jr. and B. Bahor (Belco Pollution Control Corp.), "Air Emissions Tests of a Deutsche Babcock Anlagen Dry Scrubber System at the Munich North Refuse-Fired Power Plant," Presented at: 78th Annual Meeting of the Pollution Control Association, Detroit, MI, June 1985.

66. Clean Air Engineering, *Results of Diagnostic and Compliance Testing at NSP French Island Generating Facility Conducted May 17 - 19, 1989*, July 1989.

67. *Preliminary Report on Occidental Chemical Corporation EFW. New York State Department of Environmental Conservation*, (Niagara Falls), Albany, NY, January 1986.

68. H. J. Hall, Associates, *Summary Analysis on Precipitator Tests and Performance Factors, May 13-15, 1986 at Incinerator Units 1, 2 - Occidental Chemical Company*, Prepared for Occidental Chemical Company EFW. Niagara Falls, NY. June 25, 1986.

69. Anderson, C.L., et al. (Radian Corporation), *Summary Report, CDD/CDF, Metals and Particulate, Uncontrolled and Controlled Emissions, Signal Environmental Systems, Inc., North Andover RESCO, North Andover, MA*, U. S. Environmental Protection Agency, Research Triangle Park, NC, EMB Report No. 86-MINO2A, March 1988.

70. York Services Corporation, *Final Report for a Test Program on the Municipal Incinerator Located at Northern Aroostook Regional Airport, Frenchville, Maine*, Prepared for Northern Aroostook Regional Incinerator Frenchville, ME. January 26, 1987.

71. Radian Corporation, *Results From the Analysis of MSW Incinerator Testing at Oswego County, New York*, Prepared for New York State Energy Research and Development Authority. March 1988.

72. Radian Corporation, *Data Analysis Results for Testing at a Two-Stage Modular MSW Combustor: Oswego County ERF, Fulton, New York*, Prepared for New York State's Energy Research and Development Authority. Albany, NY. November 1988.

73. Fossa, A.J., et al., *Phase I Resource Recovery Facility Emission Characterization Study, Overview Report*, (Oneida, Peekskill), New York State Department of Environmental Conservation, Albany, NY, May 1987.

74. Radian Corporation, *Results from the Analysis of MSW Incinerator Testing at Peekskill, New York*, Prepared for New York State Energy Research and Development Authority, DCN:88-233-012-21, August 1988.

75. Radian Corporation, *Results from the Analysis of MSW Incinerator Testing at Peekskill, New York (DRAFT)*, (Prepared for the New York State Energy Research and Development Authority), Albany, NY, March 1988.

76. Ogden Martin Systems of Pennsauken, Inc., *Pennsauken Resource Recovery Project, BACT Assessment for Control of NO_x Emissions, Top-Down Technology Consideration*, Fairfield, NJ, pp. 11, 13, December 15, 1988.

77. Roy F. Weston, Incorporated, *Penobscot Energy Recovery Company Facility, Orrington, Maine, Source Emissions Compliance Test Report Incinerator Units A and B (Penobscot, Maine)*, Prepared for GE Company September 1988.

78. Zaitlin, S., *Air Emission License Finding of Fact and Order, Penobscot Energy Recovery Company, Orrington, ME*, State of Maine, Department of Environmental Protection, Board of Environmental Protection, February 26, 1986.

79. Neulicht, R. (Midwest Research Institute), *Emissions Test Report: City of Philadelphia Northwest and East Central Municipal Incinerators*, Prepared for the U. S. Environmental Protection Agency, Philadelphia, PA. October 31, 1985.

80. Letter with attachments from Gehring, Philip, Plant Manager (Pigeon Point Energy Generating Facility), to Farmer, Jack R., Director, ESD, OAQPS, U. S. Environmental Protection Agency, June 30, 1988.

81. Entropy Environmentalists, Inc., *Stationary Source Sampling Report, Signal RESCO, Pinellas County Resource Recovery Facility, St. Petersburg, Florida, CARB/DER Emission Testing, Unit 3 Precipitator Inlets and Stack*, February and March 1987.

82. Midwest Research Institute, *Results of the Combustion and Emissions Research Project at the Vicon Incinerator Facility in Pittsfield, Massachusetts*, Prepared for New York State Energy Research and Development Authority, June 1987.

83. Response to Clean Air Act Section 114 Information Questionnaire, Results of Non-Criteria Pollutant Testing Performed at Pope-Douglas Waste to Energy Facility, July 1987, Provided to EPA on May 9, 1988.

84. Engineering Science, Inc., *A Report on Air Emission Compliance Testing at the Regional Waste Systems, Inc. Greater Portland Resource Recovery Project*, Prepared for Dravo Energy Resources, Inc., Pittsburgh, PA, March 1989.

85. Woodman, D.E., *Test Report Emission Tests, Regional Waste Systems, Portland, ME*, February 1990.

86. Environment Canada, *The National Incinerator Testing and Evaluation Program: Two State Combustion*, Report EPS 3/up/1, (Prince Edward Island), September 1985.

87. *Statistical Analysis of Emission Test Data from Fluidized Bed Combustion Boilers at Prince Edward Island, Canada*, U. S. Environmental Protection Agency, Publication No. EPA-450/3-86-015, December 1986.

88. *The National Incinerator Testing and Evaluation Program: Air Pollution Control Technology*, EPS 3/UP/2, (Quebec City), Environment Canada, Ottawa, September 1986.

89. Lavalin, Inc., *National Incinerator Testing and Evaluation Program: The Combustion Characterization of Mass Burning Incinerator Technology; Quebec City (DRAFT)*, (Prepared for Environmental Protection Service, Environmental Canada), Ottawa, Canada, September 1987.

90. Environment Canada, *NITEP, Environmental Characterization of Mass Burning Incinerator Technology at Quebec City. Summary Report*, EPS 3/UP/5. June 1988.

91. Interpoll Laboratories, *Results of the March 21 - 26, 1988, Air Emission Compliance Test on the No. 2 Boiler at the Red Wing Station, Test IV (High Load)*, Prepared for Northern States Power Company, Minneapolis, MN, Report No. 8-2526, May 10, 1988.

92. Interpoll Laboratories, *Results of the May 24-27, 1988 High Load Compliance Test on Unit 1 and Low Load Compliance Test on Unit 2 at the NSP Red Wing Station*, Prepared for Northern States Power Company, Minneapolis, MN, Report No. 8-2559, July 21, 1988.

93. Cal Recovery Systems, Inc., *Final Report, Evaluation of Municipal Solid Waste Incineration. (Red Wing, Minnesota facility) Submitted to Minnesota Pollution Control Agency*, Report No. 1130-87-1, January 1987.

94. Eastmount Engineering, Inc., *Final Report, Waste-to-Energy Resource Recovery Facility, Compliance Test Program, Volumes II-V*, (Prepared for SEMASS Partnership.), March 1990.

95. McClanahan, D (Fluor Daniel), A. Licata (Dravo), and J. Buschmann (Flakt, Inc.)., "Operating Experience with Three APC Designs on Municipal Incinerators." Proceedings of the International Conference on Municipal Waste Combustion, pp. 7C-19 to 7C-41, (Springfield), April 11-14, 1988.

96. Interpoll Laboratories, Inc., *Results of the June 1988 Air Emission Performance Test on the MSW Incinerators at the St. Croix Waste to Energy Facility in New Richmond, Wisconsin*, Prepared for American Resource Recovery, Waukesha, WI, Report No. 8-2560, September 12, 1988.

97. Interpoll Laboratories, Inc, *Results of the June 6, 1988, Scrubber Performance Test at the St. Croix Waste to Energy Incineration Facility in New Richmond, Wisconsin*, Prepared for Interel Corporation, Englewood, CO, Report No. 8-2560I, September 20, 1988.

98. Interpoll Laboratories, Inc., *Results of the August 23, 1988, Scrubber Performance Test at the St. Croix Waste to Energy Incineration Facility in New Richmond, Wisconsin*, Prepared for Interel Corporation, Englewood, CO, Report No. 8-2609, September 20, 1988.

99. Interpoll Laboratories, Inc., *Results of the October 1988 Particulate Emission Compliance Test on the MSW Incinerator at the St. Croix Waste to Energy Facility in New Richmond, Wisconsin*, Prepared for American Resource Recovery, Waukesha, WI, Report No. 8-2547, November 3, 1988.

100. Interpoll Laboratories, Inc., *Results of the October 21, 1988, Scrubber Performance Test at the St. Croix Waste to Energy Facility in New Richmond, Wisconsin*, Prepared for Interel Corporation, Englewood, CO, Report No. 8-2648, December 2, 1988.

101. Hahn, J. L. (Ogden Projects, Inc.), *Environmental Test Report*, Prepared for Stanislaus Waste Energy Company Crows Landing, CA, OPI Report No. 177R, April 7, 1989.

102. Hahn, J.L. and D.S. Sofaer, "Air Emissions Test Results from the Stanislaus County, California Resource Recovery Facility", Presented at the International Conference on Municipal Waste Combustion, Hollywood, FL, pp. 4A-1 to 4A-14, April 11-14, 1989.

103. Seelinger, R., et al. (Ogden Products, Inc.), *Environmental Test Report, Walter B. Hall Resource Recovery Facility, Units 1 and 2*, (Prepared for Ogden Martin Systems of Tulsa, Inc.), Tulsa, OK, September 1986.

104. PEI Associates, Inc, *Method Development and Testing for Chromium, Municipal Refuse Incinerator, Tuscaloosa Energy Recovery, Tuscaloosa, Alabama*, U. S. Environmental Protection Agency, Research Triangle Park, NC, EMB Report 85-CHM-9, January 1986.

105. Guest, T. and O. Knizek, "Mercury Control at Burnaby's Municipal Waste Incinerator", Proceedings of the 84th Annual Meeting and Exhibition of the Air and Waste Management Association, Vancouver, British Columbia, Canada, June 16-21, 1991.

106. Trip Report, Burnaby MWC, British Columbia, Canada. White, D., Radian Corporation, May 1990.

107. Entropy Environmentalists, Inc. for Babcock & Wilcox Co. North County Regional Resource Recovery Facility, West Palm Beach, FL, October 1989.

108. Maly, P.M., G.C. England. W.R. Seeker, N.R. Soelberg, and D.G. Linz. *Results of the July 1988 Wilmarth Boiler Characterization Tests*, Gas Research Institute Topical Report No. GRI-89/0109, June 1988-March 1989.

109. Hahn, J.L. (Cooper Engineers, Inc.), *Air Emissions Testing at the Martin GmbH Waste-to-Energy Facility in Wurzburg, West Germany*, Prepared for Ogden Martin Systems, Inc., Paramus, NJ, January 1986.

110. Entropy Environmentalists, Inc. for Westinghouse RESD, *Metals Emission Testing Results, Conducted at the York County Resource Recovery Facility*, February 1991.

111. Entropy Environmentalists, Inc. for Westinghouse RESD, *Emissions Testing for: Hexavalent Chromium, Metals, Particulate. Conducted at the York County Resource Recovery Facility*, July 31 - August 4, 1990.

112. Interpoll Laboratories, *Results of the July 1987 Emission Performance Tests of the Pope/Douglas Waste-to-Energy Facility MSW Incinerators in Alexandria, Minnesota*, (Prepared for HDR Techserv, Inc.), Minneapolis, MN, October 1987.

113. Sussman, D.B., Ogden Martin System, Inc., Submittal to Air Docket (LE-131), Docket No. A-89-08, Category IV-M, Washington, DC, October 1990.

114. Ferraro, F., Wheelabrator Technologies, Inc., Data package to D.M. White, Radian Corporation, February 1991.

115. Knisley, D.R., et al. (Radian Corporation), *Emissions Test Report, Dioxin/Furan Emission Testing, Refuse Fuels Associates, Lawrence, Massachusetts*, (Prepared for Refuse Fuels Association), Haverhill, MA, June 1987.

116. Entropy Environmentalists, Inc., *Stationary Source Sampling Report, Ogden Martin Systems of Haverhill, Inc., Lawrence, Massachusetts Thermal Conversion Facility. Particulate, Dioxins/Furans and Nitrogen Oxides Emission Compliance Testing*. September 1987.

117. Fossa, A.J., et al., *Phase I Resource Recovery Facility Emission Characterization Study, Overview Report*, New York State Department of Environmental Conservation, Albany, NY. May 1987.

118. Telecon. DeVan, S. Oneida ERF, with Vancil, M.A., Radian Corporation. April 4, 1988. Specific collecting area of ESP's.

119. Higgins, G.M. *An Evaluation of Trace Organic Emissions from Refuse Thermal Processing Facilities (North Little Rock, Arkansas; Mayport Naval Station, Florida; and Wright Patterson Air Force Base, Ohio)*, Prepared for U. S. Environmental Protection Agency/Office of Solid Waste by Systech Corporation, July 1982.

120. Kerr, R., et al., *Emission Source Test Report--Sheridan Avenue RDF Plant, Answers (Albany, New York)*, Division of Air Resources, New York State Department of Environmental Conservation, August 1985.

121. U. S. Environmental Protection Agency, Emission Factor Documentation for AP-42 Section 2.1, Refuse Combustion, Research Triangle Park, NC, May 1993.

122. *Air Pollutant Emission Factors*, APTD-0923, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1970.

123. *Control Techniques For Carbon Monoxide Emissions From Stationary Sources*, AP-65, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1970.

124. *Air Pollution Engineering Manual*, AP-40, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1967.

125. J. DeMarco. et al., *Incinerator Guidelines 1969*, SW. 13TS, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1969.

126. *Municipal Waste Combustors - Background Information for Proposed Guidelines for Existing Facilities*, U. S. Environmental Protection Agency, Research Triangle Park, NC, EPA-450/3-89-27e, August 1989.

127. *Municipal Waste Combustors - Background Information for Proposed Standards: Control of NO_x Emissions* U. S. Environmental Protection Agency, Research Triangle Park, NC, EPA-450/3-89-27d, August 1989.

127. J.O. Brukle, J.A. Dorsey, and B.T. Riley, "The Effects of Operating Variables and Refuse Types on Emissions from a Pilot-scale Trench Incinerator," Proceedings of the 1968 Incinerator Conference, American Society of Mechanical Engineers, New York, NY, May 1968.

128. Nessen, W.R., *Systems Study of Air Pollution from Municipal Incineration*, Arthur D. Little, Inc., Cambridge, MA, March 1970.

130. C.R. Brunner, *Handbook of Incineration Systems*, McGraw-Hill, Inc., pp. 10.3-10.4, 1991.

131. Telecon Report, Personal communication between K. Quincey, Radian Corporation and E. Raulerson, Florida Department of Environmental Regulations, February 16, 1993.

132. Telecon Report, Personal communications between K. Nebel and K. Quincey, Radian Corporation and M. McDonnold, Simonds Manufacturing, February 16, 1993.

133. Telecon Report, Personal communications between K. Quincey, Radian Corporation and R. Crochet, Crochet Equipment Company, February 16 and 26, 1993.

134. Telecon Report, Personal communication between K. Quincey, Radian Corporation and T. Allen, NC Division of Environmental Management, February 16, 1993.

2.5 SEWAGE SLUDGE INCINERATION

There are approximately 170 sewage sludge incineration (SSI) plants in operation in the United States. Three main types of incinerators are used: multiple hearth, fluidized bed, and electric infrared. Some sludge is co-fired with municipal solid waste in combustors based on refuse combustion technology (see Section 2.1). Refuse co-fired with sludge in combustors based on sludge incinerating technology is limited to multiple hearth incinerators only.

Over 80 percent of the identified operating sludge incinerators are of the multiple hearth design. About 15 percent are fluidized bed combustors and 3 percent are electric. The remaining combustors co-fire refuse with sludge. Most sludge incinerators are located in the Eastern United States, though there are a significant number on the West Coast. New York has the largest number of facilities with 33. Pennsylvania and Michigan have the next-largest numbers of facilities with 21 and 19 sites, respectively.

Sewage sludge incinerator emissions are currently regulated under 40 CFR Part 60, Subpart 0 and 40 CFR Part 61, Subparts C and E. Subpart 0 in Part 60 establishes a New Source Performance Standard for particulate matter. Subparts C and E of Part 61--National Emission Standards for Hazardous Air Pollution (NESHAP)--establish emission limits for beryllium and mercury, respectively.

In 1989, technical standards for the use and disposal of sewage sludge were proposed as 40 CFR Part 503, under authority of Section 405 of the Clean Water Act. Subpart G of this proposed Part 503 proposes to establish national emission limits for arsenic, beryllium, cadmium, chromium, lead, mercury, nickel, and total hydrocarbons from sewage sludge incinerators. The proposed limits for mercury and beryllium are based on the assumptions used in developing the NESHAP's for these pollutants, and no additional controls were proposed to be required. Carbon monoxide emissions were examined, but no limit was proposed.

2.5.1 Process Description[1,2]

Types of incineration described in this section include:

- Multiple hearth,
- Fluidized bed, and
- Electric.

Single hearth cyclone, rotary kiln, and wet air oxidation are also briefly discussed.

2.5.1.1 Multiple Hearth Furnaces -- The multiple hearth furnace was originally developed for mineral ore roasting nearly a century ago. The air-cooled variation has been used to incinerate sewage sludge since the 1930s. A cross-sectional diagram of a typical multiple hearth furnace is shown in Figure 2.5-1. The basic multiple hearth furnace (MHF) is a vertically oriented cylinder. The outer shell is constructed of steel, lined with refractory, and surrounds a series of horizontal refractory hearths. A hollow cast iron rotating shaft runs through the center of the hearths. Cooling

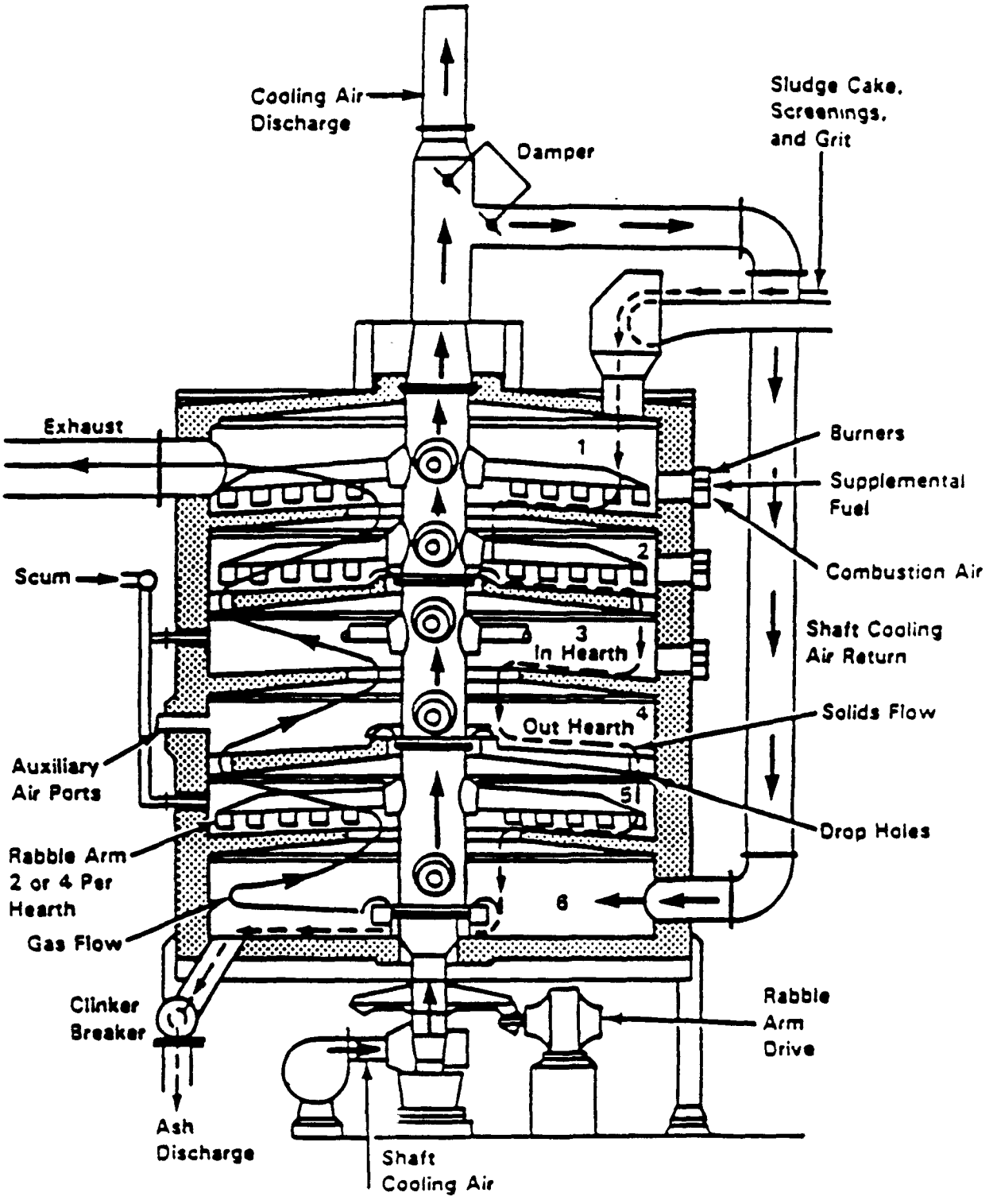


Figure 2.5-1. Cross Section of a Multiple Hearth Furnace

air is introduced into the shaft which extend above the hearths. Each rabble arm is equipped with a number of teeth, approximately 6 inches in length, and spaced about 10 inches apart. The teeth are shaped to rake the sludge in a spiral motion, alternating in direction from the outside in, to the inside out, between hearths. Typically, the upper and lower hearths are fitted with four rabble arms, and the middle hearths are fitted with two. Burners, providing auxiliary heat, are located in the sidewalls of the hearths.

In most multiple hearth furnaces, partially dewatered sludge is fed onto the perimeter of the top hearth. The rabble arms move the sludge through the incinerator by raking the sludge toward the center shaft where it drops through holes located at the center of the hearth. In the next hearth the sludge is raked in the opposite direction. This process is repeated in all of the subsequent hearths. The effect of the rabble motion is to break up solid material to allow better surface contact with heat and oxygen. A sludge depth of about 1 inch is maintained in each hearth at the design sludge flow rate.

Scum may also be fed to one or more hearths of the incinerator. Scum is the material that floats on wastewater. It is generally composed of vegetable and mineral oils, grease, hair, waxes, fats, and other materials that will float. Scum may be removed from many treatment units including preaeration tanks, skimming tanks, and sedimentation tanks. Quantities of scum are generally small compared to those of other wastewater solids.

Ambient air is first ducted through the central shaft and its associated rabble arms. A portion, or all, of this air is then taken from the top of the shaft and recirculated into the lowermost hearth as preheated combustion air. Shaft cooling air which is not circulated back into the furnace is ducted into the stack downstream of the air pollution control devices. The combustion air flows upward through the drop holes in the hearths, countercurrent to the flow of the sludge, before being exhausted from the top hearth. Air enters the bottom to cool the ash. Provisions are usually made to inject ambient air directly into on the middle hearths as well.

From the standpoint of the overall incineration process, multiple hearth furnaces can be divided into three zones. The upper hearths comprise the drying zone where most of the moisture in the sludge is evaporated. The temperature in the drying zone is typically between 425 and 760°C (800 and 1400°F). Sludge combustion occurs in the middle hearths (second zone) as the temperature is increased to about 925°C (1700°F). The combustion zone can be further subdivided into the upper-middle hearths where the volatile gases and solids are burned, and the lower-middle hearths where most of the fixed carbon is combusted. The third zone, made up of the lowermost hearth(s), is the cooling zone. In this zone the ash is cooled as its heat is transferred to the incoming combustion air.

Multiple hearth furnaces are sometimes operated with afterburners to further reduce odors and concentrations of unburned hydrocarbons. In afterburning, furnace exhaust gases are ducted to a chamber where they are mixed with supplemental fuel and air and completely combusted. Some incinerators have the flexibility to allow sludge to be fed to a lower hearth, thus allowing the upper hearth(s) to function essentially as an afterburner.

Under normal operating condition, 50 to 100 percent excess air must be added to a MHF in order to ensure complete combustion of the sludge. Besides enhancing contact between fuel and oxygen in the furnace, these relatively high rates of excess air are necessary to compensate for normal variations in both the organic characteristics of the sludge feed and the rate at which it enters the incinerator. When an inadequate amount of excess air is available, only partial oxidation of the

carbon will occur, with a resultant increase in emissions of carbon monoxide, soot, and hydrocarbons. Too much excess air, on the other hand, can cause increased entrainment of particulate and unnecessarily high auxiliary fuel consumption.

Multiple hearth furnace emissions are usually controlled by a venturi scrubber, an impingement tray scrubber, or a combination of both. Wet cyclones and dry cyclones are also used. Wet electrostatic precipitators (ESPs) are being installed as retrofits where tighter limits on particulate matter and metals are required by State regulations.

2.5.1.2 Fluidized Bed Incinerators -- Fluidized bed technology was first developed by the petroleum industry to be used for catalyst regeneration. Figure 2.5-2 shows the cross section diagram of a fluidized bed furnace. Fluidized bed combustors (FBCs) consist of vertically oriented outer shell constructed of steel and lined with refractory. Tuyeres (nozzles designed to deliver blasts of air) are located at the base of the furnace within a refractory-lined grid. A bed of sand, approximately 0.75 meters (2.5 feet) thick, rests upon the grid. Two general configurations can be distinguished on the basis of how the fluidizing air is injected into the furnace. In the "hot windbox" design the combustion air is first preheated by passing through a heat exchanger where heat is recovered from the hot flue gases. Alternatively, ambient air can be injected directly into the furnace from a cold windbox.

Partially dewatered sludge is fed into the lower portion of the furnace. Air injected through the tuyeres, at pressure of from 20 to 35 kilopascals (3 to 5 pounds per square inch grade), simultaneously fluidizes the bed of hot sand and the incoming sludge. Temperatures of 750 to 925°C (1400 to 1700°F) are maintained in the bed. Residence times are typically 2 to 5 seconds. As the sludge burns, fine ash particles are carried out the top of the furnace. Some sand is also removed in the air stream; sand make-up requirements are on the order of 5 percent for every 300 hours of operation.

Combustion of the sludge occurs in two zones. Within the bed itself (Zone 1) evaporation of the water and pyrolysis of the organic materials occur nearly simultaneously as the temperature of the sludge is rapidly raised. In the second zone, (freeboard area) the remaining free carbon and combustible gases are burned. The second zone functions essentially as an afterburner.

Fluidization achieves nearly ideal mixing between the sludge and the combustion air and the turbulence facilitates the transfer of heat from the hot sand to the sludge. The most noticeable impact of the better burning atmosphere provided by a fluidized bed incinerator is seen in the limited amount of excess air required for complete combustion of the sludge. Typically, FBCs can achieve complete combustion with 20 to 50 percent excess air, about half the excess air required by multiple hearth furnaces. As a consequence, FBC incinerators have generally lower fuel requirements compared to MHF incinerators.

Fluidized bed incinerators most often have venturi scrubbers or venturi/impingement tray scrubber combinations for emissions control.

2.5.1.3 Electric Infrared Incinerators -- The first electric infrared furnace was installed in 1975, and their use is not common. Electric infrared incinerators consist of a horizontally oriented, insulated furnace. A woven wire belt conveyor extends the length of the furnace and infrared heating elements are located in the roof above the conveyor belt. Combustion air is preheated by the flue gases and is injected into the discharge end of the furnace. Electric infrared incinerators consist of a number of

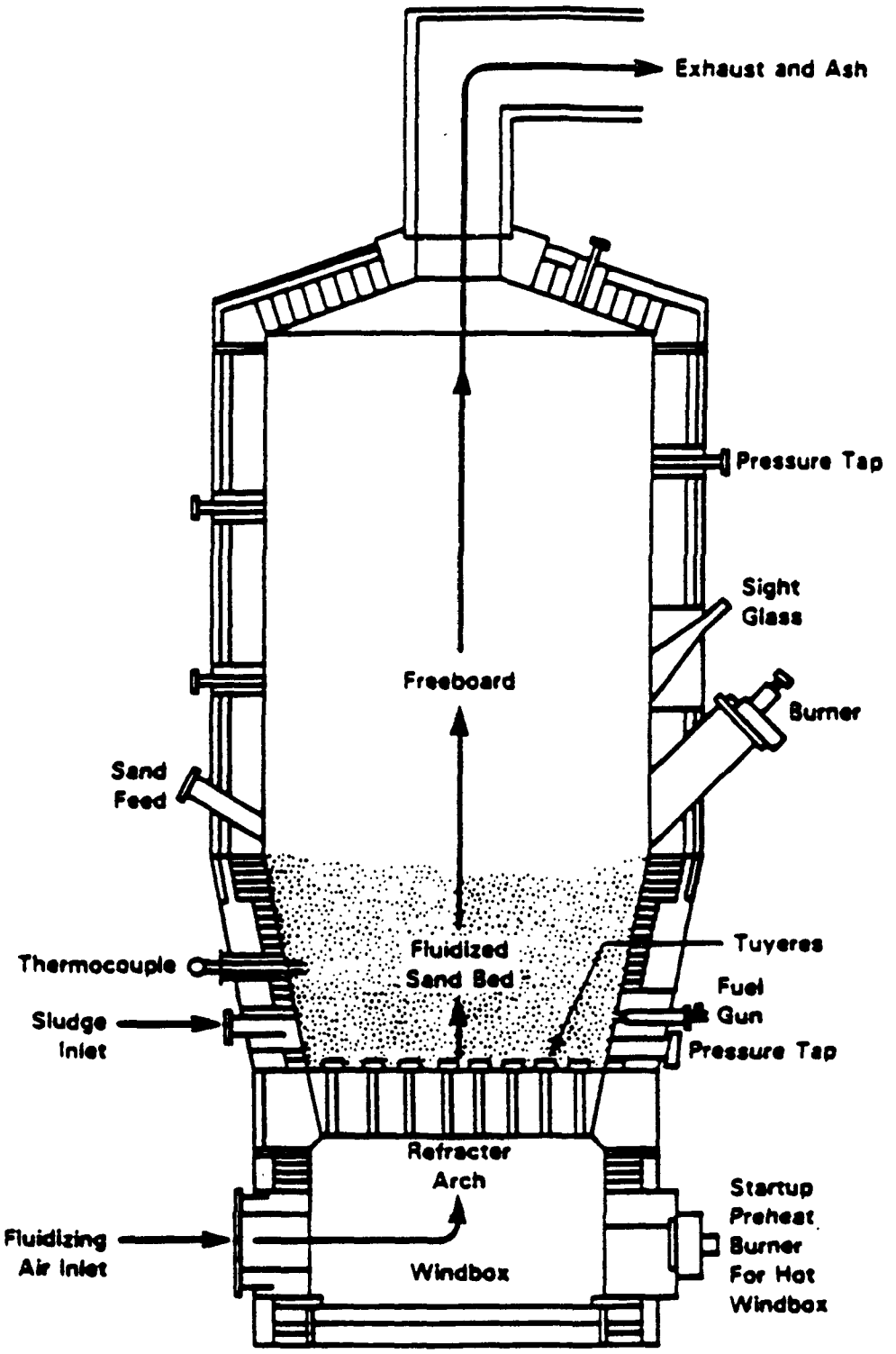


Figure 2.5-2. Cross Section of a Fluidized Bed Furnace

prefabricated modules, which can be linked together to provide the necessary furnace length. A cross section of an electric furnace is shown in Figure 2.5-3.

The dewatered sludge cake is conveyed into one end of the incinerator. An internal roller mechanism levels the sludge into a continuous layer approximately one inch thick across the width of the belt. The sludge is sequentially dried and then burned as it moves beneath the infrared heating elements. Ash is discharged into a hopper at the opposite end of the furnace. The preheated combustion air enters the furnace above the ash hopper and is further heated by the outgoing ash. The direction of air flow is countercurrent to the movement of the sludge along the conveyor. Exhaust gases leave the furnace at the feed end. Excess air rates vary from 20 to 70 percent.

Compared to MHF and FBC technologies, the electric infrared furnace offers the advantage of lower capital cost, especially for smaller systems. However, electricity costs in some areas may make an electric furnace infeasible. One other concern is replacement of various components such as the woven wire belt and infrared heaters, which have 3- to 5-year lifetimes.

Electric infrared incinerator emissions are usually controlled with a venturi scrubber or some other wet scrubber.

2.5.1.4 Other Technologies -- A number of other technologies have been used for incineration of sewage sludge, including cyclonic reactors, rotary kilns, and wet oxidation reactors. These processes are not in widespread use in the United States and will be discussed only briefly.

The cyclonic reactor is designed for small capacity applications. It is constructed of a vertical cylindrical chamber that is lined with refractory. Preheated combustion air is introduced into the chamber tangentially at high velocities. The sludge is sprayed radially toward the hot refractory walls. Combustion is rapid: The residence time of the sludge in the chamber is on the order of 10 seconds. The ash is removed with the flue gases.

Rotary kilns are also generally used for small capacity applications. The kiln is inclined slightly from the horizontal plane, with the upper end receiving both the sludge feed and the combustion air. A burner is located at the lower end of the kiln. The circumference of the kiln rotates at a speed of about 6 inches per second. Ash is deposited into a hopper located below the burner.

The wet oxidation process is not strictly one of incineration; it instead utilizes oxidation at elevated temperature and pressure in the presence of water (flameless combustion). Thickened sludge, at about 6 percent solids, is first ground and mixed with a stoichiometric amount of compressed air. The slurry is then pressurized. The mixture is then circulated through a series of heat exchangers before entering a pressurized reactor. The temperature of the reactor is held between 175 and 315°C (350 and 600°F). The pressure is normally 7,000 to 12,500 kilopascals (1,000 to 1,800 pounds per square inch grade). Steam is usually used for auxiliary heat. The water and remaining ash are circulated out the reactor and are finally separated in a tank or lagoon. The liquid phase is recycled to the treatment plant. Off-gases must be treated to eliminate odors: wet scrubbing, afterburning or carbon absorption may be used.

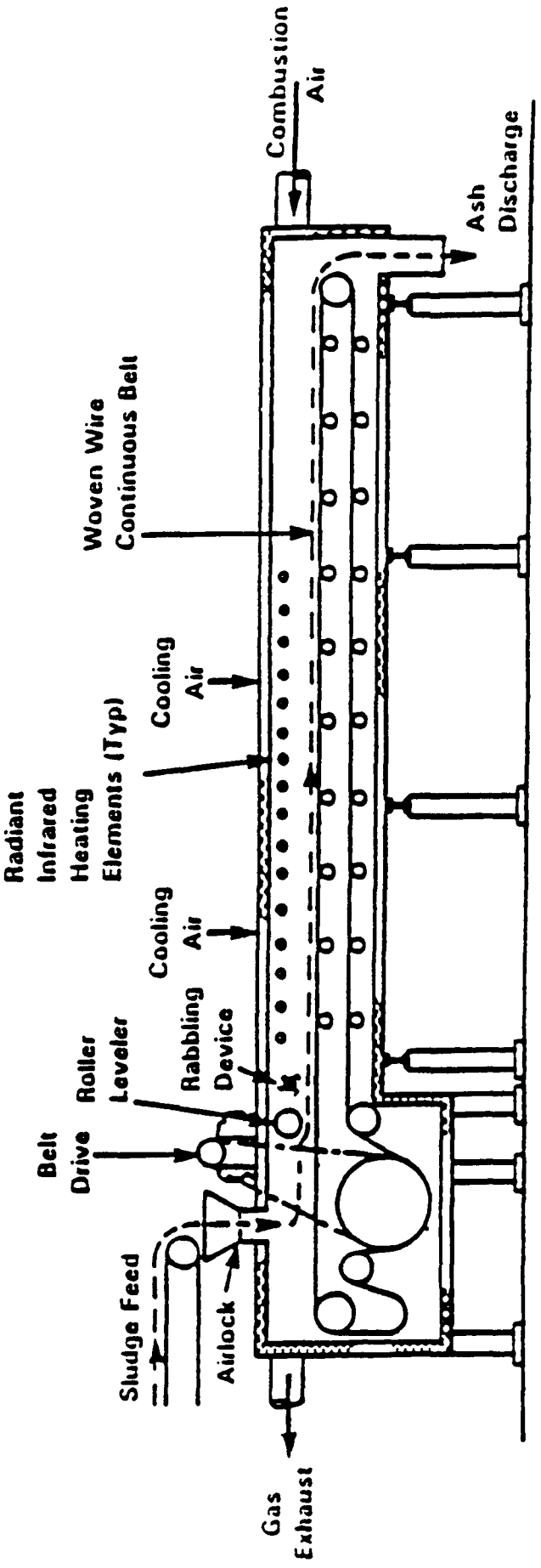


Figure 2.5-3. Cross Section of an Electric Infrared Furnace

2.5.1.5 Co-Incineration and Co-Firing -- Wastewater treatment plant sludge generally has a high water content and in some cases, fairly high levels of inert materials. As a result, its net fuel value is often low. If sludge is combined with other combustible materials in a co-incineration scheme, a furnace feed can be created that has both a low water concentration and a heat value high enough to sustain combustion with little or no supplemental fuel.

Virtually any material that can be burned can be combined with sludge in a co-incineration process. Common materials for co-combustion are coal, municipal solid waste (MSW), wood waste and agriculture waste. Thus, a municipal or industrial waste can be disposed of while providing an autogenous (self-sustaining) sludge feed, thereby solving two disposal problems.

There are two basic approaches to combusting sludge with MSW: 1) use of MSW combustion technology by adding dewatered or dried sludge to the MSW combustion unit, and 2) use of sludge combustion technology by adding processed MSW as a supplemental fuel to the sludge furnace. With the latter, MSW is processed by removing noncombustibles, shredding, air classifying, and screening. Waste that is more finely processed is less likely to cause problems such as severe erosion of the hearths, poor temperature control, and refractory failures.

2.5.2 Emissions and Controls[1-3]

Sewage sludge incinerators potentially emit significant quantities of pollutants. The major pollutants emitted are: 1) particulate matter, 2) metals, 3) carbon monoxide (CO), 4) nitrogen oxides (NO_x), 5) sulfur dioxide (SO_2), and 6) unburned hydrocarbons. Partial combustion of sludge can result in emissions of intermediate products of incomplete combustion (PIC), including toxic organic compounds.

Uncontrolled particulate emission rates vary widely depending on the type of incinerator, the volatiles and moisture content of the sludge, and the operating practices employed. Generally, uncontrolled particulate emissions are highest from fluidized bed incinerators because suspension burning results in much of the ash being carried out of the incinerator with the flue gas. Uncontrolled emissions from multiple hearth and fluidized bed incinerators are extremely variable, however. Electric incinerators appear to have the lowest rates of uncontrolled particulate release of the three major furnace types, possibly because the sludge is not disturbed during firing. In general, higher airflow rates increase the opportunity for particulate matter to be entrained in the exhaust gases. Sludge with low volatile content or high moisture content may compound this situation by requiring more supplemental fuel to burn. As more fuel is consumed, the amount of air flowing through the incinerator is also increased. However, no direct correlation has been established between air flow and particulate emissions.

Metals emissions are affected by metals content of the sludge, fuel bed temperature, and the level of particulate matter control. Since metals which are volatilized in the combustion zone condense in the exhaust gas stream, most metals (except mercury) are associated with fine particulate and are removed as the fine particulates are removed.

Carbon monoxide is formed when available oxygen is insufficient for complete combustion or when excess air levels are too high, resulting in lower combustion temperatures.

Nitrogen and sulfur oxide emissions are primarily the result of oxidation of nitrogen and sulfur in the sludge. Therefore, these emissions can vary greatly based on local and seasonal sewage characteristics.

Emissions of volatile organic compounds also vary greatly with incinerator type and operation. Incinerators with countercurrent air flow such as multiple hearth designs provide the greatest opportunity for unburned hydrocarbons to be emitted. In the MHF, hot air and wet sludge feed are contacted at the top of the furnace. Any compounds distilled from the solids are immediately vented from the furnace at temperatures too low to completely destruct them.

Particulate emissions from sewage sludge incinerators have historically been controlled by wet scrubbers, since the associated sewage treatment plant provides both a convenient source and a good disposal option for the scrubber water. The types of existing sewage sludge incinerator controls range from low pressure drop spray towers and wet cyclones to higher pressure drop venturi scrubbers and venturi/impingement tray scrubber combinations. Electrostatic precipitators and baghouses are employed, primarily where sludge is co-fired with municipal solid waste. The most widely used control device applied to a multiple hearth incinerator is the impingement tray scrubber. Older units use the tray scrubber alone while combination venturi/impingement tray scrubbers are widely applied to newer multiple hearth incinerators and to fluidized bed incinerators. Most electric incinerators and many fluidized bed incinerators use venturi scrubbers only.

In a typical combination venturi/impingement tray scrubber, hot gas exits the incinerator and enters the precooling or quench section of the scrubber. Spray nozzles in the quench section cool the incoming gas and the quenched gas then enters the venturi section of the control device. Venturi water is usually pumped into an inlet weir above the quencher. The venturi water enters the scrubber above the throat and floods the throat completely. This eliminates build-up of solids and reduces abrasion. Turbulence created by high gas velocity in the converging throat section deflects some of the water traveling down the throat into the gas stream. Particulate matter carried along with the gas stream impacts on these water particles and on the water wall. As the scrubber water and flue gas leave the venturi section, they pass into a flooded elbow where the stream velocity decreases, allowing the water and gas to separate. Most venturi sections come equipped with variable throats. By restricting the throat area within the venturi, the linear gas velocity is increased and the pressure drop is subsequently increased. Up to a certain point, increasing the venturi pressure drop increases the removal efficiency. Venturi scrubbers typically maintain 60 to 99 percent removal efficiency for particulate matter, depending on pressure drop and particle size distribution.

At the base of the flooded elbow, the gas stream passes through a connecting duct to the base of the impingement tray tower. Gas velocity is further reduced upon entry to the tower as the gas stream passes upward through the perforated impingement trays. Water usually enters the trays from inlet ports on opposite sides and flows across the tray. As gas passes through each perforation in the tray, it creates a jet which bubbles up the water and further entrains solid particles. At the top of the tower is a mist eliminator to reduce the carryover of water droplets in the stack effluent gas. The impingement section can contain from one to four trays, but most systems for which data are available have two or three trays.

Emission factors and emission factor ratings for multiple hearth sewage sludge incinerators are shown in Tables 2.5-1 through 2.5-5. Tables 2.5-6 through 2.5-8 present emission factors for fluidized bed sewage sludge incinerators. Table 2.5-9 presents the available emission factors for electric infrared incinerators. Tables 2.5-10 and 2.5-11 present the cumulative particle size distribution and size specific emission factors for sewage sludge incinerators. Figures 2.5-4, 2.5-5, and 2.5-6 present cumulative particle size distribution and size-specific emission factors for multiple-hearth, fluidized-bed, and electric infrared incinerators, respectively.

Table 2.5-1 (Metric and English Units). CRITERIA POLLUTANT EMISSION FACTORS FOR MULTIPLE HEARTH SEWAGE SLUDGE INCINERATORS[a]
(SCC 50100515)

Source Category[b]	Particulate matter (PM)			Sulfur dioxide (SO_2)			Nitrogen oxides (NO_x)		
	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating
Uncontrolled	5.2E+01	1.0E+02	B	1.4E+01	2.8E+01	B	4.3E+00	8.6E+00	D
Controlled									
Cyclone	2.0E+00	4.0E+00	E	2.8E+00	5.6E+00	E	4.0E-03	8.0E-03	E
Cyclone/impingement	4.0E-01	8.0E-01	E						
Cyclone/venturi	2.5E-01	5.0E-01	D						
Cyclone/venturi/ impingement	3.1E-01	6.2E-01	E						
Electrostatic precipitator									
Fabric filter	2.0E-03	4.0E-03	E						
Impingement	7.0E-01	1.4E+00	B	3.2E-01	6.4E-01	D	2.7E+00	5.4E+00	D
Venturi	1.6E+00	3.2E+00	B	2.3E+00	4.6E+00	E	1.0E+00	2.0E+00	E
Venturi/impingement/ afterburner									
Venturi/impingement	1.1E+00	2.2E+00	A	1.0E-01	2.0E-01	E	8.0E-02	1.6E-01	E
Venturi/impingement/ WESP	2.0E-01	4.0E-01	E						
Venturi/WESP									

Table 2.5-1. (Continued)

Source Category	Carbon Monoxide (CO)			Lead[c]			Methane			Total Nonmethane Organic Compounds		
	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating
Uncontrolled	3.6E+01	7.2E+01	D	5.0E-02	1.0E-01	B				8.4E-01	1.7E+00	D
Controlled												
Cyclone				3.0E-02	6.0E-02	E				1.5E+00	3.0E+00	E
Cyclone/impingement												
Cyclone/venturi	1.3E+00	2.6E+00	E	3.0E-03	6.0E-03	E				2.2E-01	4.4E-01	E
Cyclone/venturi/ impingement				1.1E-02	2.2E-02	E						
Electrostatic precipitator				1.0E-03	2.0E-03	E						
Fabric filter												
Impingement	2.2E+00	4.4E+00	E	2.0E-02	4.0E-02	E	3.9E-01	7.8E-01	E	7.8E-01	1.6E+00	E
Venturi				9.0E-04	1.8E-03	E	3.2E+00	6.4E+00	E			
Venturi/impingement/ afterburner				5.0E-02	1.0E-01	E						
Venturi/impingement	1.7E+00	3.4E+00	E	3.0E-02	6.0E-02	B						
Venturi/impingement/ WESP												
Venturi/WESP				9.0E-05	1.8E-04	E						

[a] Units are pollutants emitted of dry sludge burned. SCC = Source Classification Code.
[b] WESP = Wet Electrostatic Precipitator.
[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.5-2 (Metric and English Units). ACID GAS EMISSION FACTORS FOR MULTIPLE HEARTH SEWAGE SLUDGE INCINERATORS[a]
(SCC 50100515)

Source Category[b]	Sulfuric Acid (H_2SO_4)			Hydrogen Chloride (HCl)[c]		
	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating
Uncontrolled	6.0E-01	1.2E+00	D			
Controlled						
Cyclone	3.3E-01	6.6E-01	E			
Cyclone/impingement				1.0E-02	2.0E-02	E
Cyclone/venturi				1.0E-02	2.0E-02	E
Cyclone/venturi/ impingement						
Electrostatic precipitator						
Fabric filter						
Impingement	5.0E-02	1.0E-01	E	1.0E-02	2.0E-02	E
Venturi				1.0E-02	2.0E-02	E
Venturi/impingement/ afterburner						
Venturi/impingement	2.0E-01	4.0E-01	E			
Venturi/impingement/ WESP						
Venturi/WESP						

[a] Units are pollutants emitted of dry sludge burned. SCC = Source Classification Code.
[b] WESP = Wet Electrostatic Precipitator.
[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.5-3 (Metric and English Units). CHLORINATED DIBENZO-P-DIOXIN (CDD) AND DIBENZOFURAN (CDF) EMISSION FACTORS FOR MULTIPLE HEARTH SEWAGE SLUDGE INCINERATORS[a]
(SCC 50100515)

EMISSION FACTOR RATING: E

Source Category[b]	2,3,7,8-TCDD[c]		Total TCDD		Total PCDD	
	μg/Mg	lb/ton	μg/Mg	lb/ton	μg/Mg	lb/ton
Uncontrolled			6.3E+01	1.3E-07	2.7E+00	5.4E-09
Controlled						
Cyclone						
Cyclone/impingement						
Cyclone/venturi			1.4E+00	2.8E-09		
Cyclone/venturi/ impingement	3.0E-01	6.0E-10				
Electrostatic precipitator						
Fabric filter						
Impingement	5.0E-01	1.0E-09	2.8E+01	5.6E-08	3.7E+00	7.4E-09
Venturi						
Venturi/impingement/ afterburner	9.0E-01	1.8E-09				
Venturi/impingement	2.0E+00	4.0E-09				
Venturi/impingement/ WESP						
Venturi/WESP						

Table 2.5-3. (Continued)

Source Category[b]	Total HxCDD[c]		Total HpCDD		Total OCDD	
	μg/Mg	lb/ton	μg/Mg	lb/ton	μg/Mg	lb/ton
Uncontrolled	6.8E+01	1.4E-07	3.4E+02	6.8E-07	3.7E+02	7.4E-07
Controlled						
Cyclone						
Cyclone/impingement						
Cyclone/venturi			8.0E-01	1.6E-09	3.4E+00	6.8E-09
Cyclone/venturi/ impingement	4.4E+00	8.8E-09	1.4E+01	2.8E-08	3.1E+01	6.7E-08
Electrostatic precipitator						
Fabric filter						
Impingement	2.4E+01	4.8E-08	7.3E+01	1.5E-07	5.3E+01	1.1E-07
Venturi						
Venturi/impingement/ afterburner	6.0E+01	1.2E-07	2.3E+01	4.6E-08	1.2E+01	2.4E-08
Venturi/impingement	3.8E+01	7.6E-08	1.5E+01	3.0E-08	1.9E+01	3.8E-08
Venturi/impingement/ WESP						
Venturi/WESP						

Table 2.5-3. (Continued)

Source Category[b]	2,3,7,8-TCDF[c]		Total TCDF[c]		Total PCDF[c]	
	μg/Mg	lb/ton	μg/Mg	lb/ton	μg/Mg	lb/ton
Uncontrolled	6.2E+02	1.2E-06	1.7E+03	3.4E-06	9.8E+02	2.0E-06
Controlled						
Cyclone						
Cyclone/impingement						
Cyclone/venturi	5.6E+00	1.1E-08	5.0E+01	1.0E-07	1.1E+01	2.2E-08
Cyclone/venturi/ impingement			1.8E+02	3.8E-07	5.7E+01	1.1E-07
Electrostatic precipitator						
Fabric filter						
Impingement	1.8E+02	3.6E-07	7.0E+02	1.4E-06	3.6E+02	7.2E-07
Venturi						
Venturi/impingement/ afterburner	5.4E+01	1.1E-07	3.5E+02	7.0E-07	1.3E+02	2.6E-07
Venturi/impingement	4.6E+01	9.2E-08	6.0E+02	1.2E-06	1.3E+00	2.6E-09
Venturi/impingement/ WESP						
Venturi/WESP						

Table 2.5-3. (Continued)

Source Category[b]	Total HxCDF[c]		Total HpCDF[c]		Total OCDF[c]	
	μg/Mg	lb/ton	μg/Mg	lb/ton	μg/Mg	lb/ton
Uncontrolled	9.9E+01	2.0E-07	4.8E+02	9.6E-07	4.9E+02	9.8E-07
Controlled						
Cyclone						
Cyclone/impingement						
Cyclone/venturi	3.4E+00	6.8E-09	9.0E-01	1.8E-09	7.0E-01	1.4E-09
Cyclone/venturi/ impingement	1.8E+00	3.6E-09	2.9E+00	5.8E-09	1.8E+00	3.6E-09
Electrostatic precipitator						
Fabric filter						
Impingement	1.1E+02	2.2E-07	2.0E+02	4.0E-07	1.5E+02	3.0E-07
Venturi						
Venturi/impingement/ afterburner	7.8E+01	1.5E-07	4.8E+01	9.6E-08	7.7E+00	1.5E-08
Venturi/impingement	5.7E+01	1.1E-07	4.1E+01	8.2E-08	6.3E+00	1.3E-08
Venturi/impingement/ WESP						
Venturi/WESP						

Table 2.5-3. (Continued)

Source Category	Total Tetra through Octa CDD		Total Tetra through Octa CDF	
	μg/Mg	lb/ton	μg/Mg	lb/ton
Uncontrolled	8.5E+02	1.7E-06	3.8E+03	7.6E-06
Controlled				
Cyclone				
Cyclone/impingement				
Cyclone/venturi	5.6E+00	1.1E-08	6.6E+01	1.3E-07
Cyclone/venturi/ impingement	1.1E+02	2.2E-07	2.5E+02	5.0E-07
Electrostatic precipitator				
Fabric filter				
Impingement	1.8E+02	3.6E-07	1.5E+03	3.0E-06
Venturi				
Venturi/impingement/ afterburner	3.1E+02	6.2E-07	4.6E+02	9.2E-07
Venturi/impingement	2.7E+02	5.4E-07	9.3E+02	1.9E-06
Venturi/impingement/ WESP				
Venturi/WESP				

[a] Units are pollutant emitted of dry sludge burned. SCC = Source Classification Code.
[b] WESP = Wet Electrostatic Precipitator.
[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.5-4 (Metric and English Units). SUMMARY OF ORGANIC COMPOUND EMISSIONS FROM MULTIPLE HEARTH SEWAGE SLUDGE INCINERATORS[a]
(SCC 50100515)

Source Category[b]	1,1,1-Trichloroethane[c]			1,1-Dichloroethane[c]			1,2-Dichloroethane[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	6.0E-02	1.2E-04	D						
Controlled									
Cyclone									
Cyclone/impingement	1.9E+00	3.8E-03	E	2.3E-01	4.6E-04	E			
Cyclone/venturi	7.0E-02	1.4E-04	E				4.0E-03	8.0E-06	E
Cyclone/venturi/ impingement									
Electrostatic precipitator									
Fabric filter									
Impingement									
Venturi									
Venturi/impingement/ afterburner	1.4E+00	2.8E-03	E				3.0E-02	6.0E-05	E
Venturi/impingement	6.1E-01	1.2E-03	D				1.0E-02	2.0E-05	E
Venturi/impingement/ WESP									
Venturi/WESP									

Table 2.5-4. (Continued)

Source Category[b]	1,2-Dichlorobenzene			1,3-Dichlorobenzene			1,4-Dichlorobenzene[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	3.7E-01	7.4E-04	E				4.1E-01	8.2E-04	E
Controlled									
Cyclone									
Cyclone/impingement									
Cyclone/venturi				5.0E-02	1.0E-04	E	7.0E-03	1.4E-05	E
Cyclone/venturi/ impingement									
Electrostatic precipitator									
Fabric filter									
Impingement									
Venturi									
Venturi/impingement/ afterburner									
Venturi/impingement	1.9E-01	3.8E-04	E	2.0E-02	4.0E-05	E	2.4E-01	4.8E-04	E
Venturi/impingement/ WESP									
Venturi/WESP									

Table 2.5-4 (Continued)

Source Category[b]	2-Nitrophenol			Acetaldehyde[c]			Acetone		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	6.0E+00	1.2E-02	E						
Controlled									
Cyclone									
Cyclone/impingement									
Cyclone/venturi	3.8E-01	7.6E-04	E						
Cyclone/venturi/ impingement									
Electrostatic precipitator									
Fabric filter									
Impingement				1.6E-01	3.2E-04	E			
Venturi							3.2E+00	6.4E-03	E
Venturi/impingement/ afterburner									
Venturi/impingement	1.2E+00	2.4E-03	E						
Venturi/impingement/ WESP									
Venturi/WESP									

Table 2.5-4. (Continued)

Source Category[b]	Acetonitrile[c]			Acrylonitrile[c]			Benzene[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	2.5E+01	5.0E-02	E	2.5E+01	5.0E-02	E	5.8E+00	1.2E-02	D
Controlled									
Cyclone									
Cyclone/impingement									
Cyclone/venturi				1.5E-01	3.0E-04	E	3.5E-01	7.0E-04	E
Cyclone/venturi/ impingement									
Electrostatic precipitator									
Fabric filter									
Impingement									
Venturi							1.4E+01	2.8E-02	E
Venturi/impingement/ afterburner	7.4E-01	1.5E-03	E	4.9E-01	9.8E-04	E	1.7E-01	3.4E-04	E
Venturi/impingement	9.7E+00	2.0E-02	E	1.7E+01	3.4E-02	E	6.3E+00	1.3E-02	D
Venturi/impingement/ WESP									
Venturi/WESP									

Table 2.5-4. (Continued)

Source Category[b]	Bis (2-ethylhexyl) phthalate[c]			Bromodichloromethane			Carbon Tetrachloride[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	9.3E-01	1.9E-03	E	4.0E-03	8.0E-06	E	1.0E-02	2.0E-05	E
Controlled									
Cyclone									
Cyclone/impingement									
Cyclone/venturi	4.0E-02	8.0E-05	E				7.0E-03	1.4E-05	E
Cyclone/venturi/ impingement									
Electrostatic precipitator									
Fabric filter									
Impingement									
Venturi				1.5E+00	3.0E-03	E			
Venturi/impingement/ afterburner							1.0E-03	2.0E-06	E
Venturi/impingement	3.2E-01	6.4E-04	E				3.0E-02	6.0E-05	D
Venturi/impingement/ WESP									
Venturi/WESP									

Table 2.5-4. (Continued)

Source Category[b]	Chlorobenzene[c]			Chloroform[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	7.5E-01	1.5E-03	E	3.0E-02	6.0E-05	E
Controlled						
Cyclone						
Cyclone/impingement						
Cyclone/venturi	6.0E-03	1.2E-05	E	2.0E-02	4.0E-05	E
Cyclone/venturi/ impingement						
Electrostatic precipitator						
Fabric filter						
Impingement						
Venturi	4.2E+00	8.4E-03	E	3.3E+00	6.6E-03	E
Venturi/impingement/ afterburner	2.6E-01	5.2E-04	E	4.9E-01	9.8E-04	E
Venturi/impingement	6.0E-01	1.2E-03	E	1.30E+00	2.6E-03	D
Venturi/impingement/ WESP						
Venturi/WESP						

Table 2.5-4. (Continued)

Source Category[b]	Ethylbenzene[c]			Formaldehyde[c]			Methyl Ethyl Ketone[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	8.0E-01	1.6E-03	E				6.1E+00	1.2E-02	E
Controlled									
Cyclone									
Cyclone/impingement									
Cyclone/venturi	3.0E-03	6.0E-06	E	1.3E+00	2.6E-03	E			
Cyclone/venturi/ impingement									
Electrostatic precipitator									
Fabric filter									
Impingement									
Venturi	6.0E+00	1.2E-02	E	4.0E-01	8.0E-04	E	6.1E+00	1.2E-02	E
Venturi/impingement/ afterburner	2.0E-02	4.0E-05	E				5.0E-02	1.0E-04	E
Venturi/impingement	1.0E+00	2.0E-03	D				8.9E+00	1.8E-02	E
Venturi/impingement/ WESP									
Venturi/WESP									

Table 2.5-4. (Continued)

Source Category[b]	Methyl Isobutyl Ketone[c]			Methylene Chloride[c]			Naphthalene[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled				4.0E-01	8.0E-04	D	9.2E+00	1.8E-02	E
Controlled									
Cyclone									
Cyclone/impingement	1.0E-02	2.0E-05	E						
Cyclone/venturi				3.0E-01	6.0E-04	E	9.7E-01	1.9E-03	D
Cyclone/venturi/ impingement									
Electrostatic precipitator									
Fabric filter									
Impingement									
Venturi									
Venturi/impingement/ afterburner				4.0E-01	8.0E-04	E			
Venturi/impingement				9.0E-01	1.8E-03	D			
Venturi/impingement/ WESP									
Venturi/WESP									

Table 2.5-4. (Continued)

Source Category[b]	Perchloroethylene[c]			Phenol[c]			Tetrachloroethane[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	4.0E-01	8.0E-04	E	2.2E+01	4.4E-02	E			
Controlled									
Cyclone									
Cyclone/impingement									
Cyclone/venturi	3.0E-01	6.0E-04	E						
Cyclone/venturi/ impingement									
Electrostatic precipitator									
Fabric filter									
Impingement									
Venturi	2.0E-01	4.0E-04	E				1.2E+01	2.4E-02	E
Venturi/impingement/ afterburner									
Venturi/impingement				1.8E+00	3.6E-03	E			
Venturi/impingement/ WESP									
Venturi/WESP									

Table 2.5-4. (Continued)

Source Category[b]	Toluene[c]			Trans-1,2-Dichloroethene[c]			Trichloroethene[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	7.8E+00	1.5E-02	D	9.0E-02	1.8E-04	E	4.0E-01	8.0E-04	E
Controlled									
Cyclone									
Cyclone/impingement									
Cyclone/venturi	3.3E+00	6.6E-03	E						
Cyclone/venturi/ impingement									
Electrostatic precipitator									
Fabric filter									
Impingement									
Venturi	1.6E+01	3.0E-02	E						
Venturi/impingement/ afterburner	6.6E-01	1.3E-03	E	4.0E-02	8.0E-05	D			
Venturi/impingement	6.5E+00	1.3E-02	D	5.0E-02	1.0E-04	E	4.5E-01	9.0E-04	E
Venturi/impingement/ WESP									
Venturi/WESP									

Table 2.5-4. (Continued)

Source Category[b]	Vinyl Chloride[c]			Xylene, m,p[c]			Xylene (total)[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	6.6E+00	1.3E-02	E				9.5E-01	1.9E-03	E
Controlled									
Cyclone									
Cyclone/impingement									
Cyclone/venturi	1.0E+00	2.0E-03	E						
Cyclone/venturi/ impingement									
Electrostatic precipitator	8.0E-01	1.6E-03	E						
Fabric filter									
Impingement									
Venturi				2.0E+00	4.0E-03	E			
Venturi/impingement/ afterburner									
Venturi/impingement	3.7E+00	7.4E-03	D						
Venturi/impingement/ WESP									
Venturi/WESP									

[a] Units are pollutants emitted of dry sludge burned. SCC = Source Classification Code.
[b] WESP = Wet Electrostatic Precipitator.
[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.5-5 (Metric and English Units). SUMMARY OF METAL EMISSIONS FROM MULTIPLE HEARTH SEWAGE SLUDGE INCINERATORS[a]
(SCC 50100515)

Source Category[b]	Aluminum			Antimony[c]			Arsenic[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	2.4E+02	4.8E-01	D	1.5E+00	3.0E-03	E	4.7E+00	9.4E-03	B
Controlled									
Cyclone	3.0E-01	6.0E-04	E	3.2E-01	6.4E-04	E			
Cyclone/impingement									
Cyclone/venturi							1.0E-01	2.0E-04	E
Cyclone/venturi/ impingement							8.5E-01	1.7E-03	E
Electrostatic precipitator	3.8E+02	7.6E-02	E	4.0E-02	8.0E-05	E	1.2E+00	2.4E-03	E
Fabric filter	6.8E-01		E	4.0E-03	8.0E-06	E	3.0E-03	6.0E-06	E
Impingement									
Venturi							5.0E-02	1.0E-04	E
Venturi/impingement/ afterburner							4.0E-02	8.0E-05	E
Venturi/impingement	9.2E+01	1.8E-01	E	2.4E-01	4.8E-04	E	6.1E-01	1.2E-03	B
Venturi/impingement/ WESP									
Venturi/WESP							6.0E-01	1.2E-03	E

Table 2.5-5. (Continued)

Source Category[b]	Barium			Beryllium[c]			Cadmium[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	1.5E+01	3.0E-02	D	1.5E-01	3.0E-04	E	1.6E+01	3.7E-02	B
Controlled									
Cyclone	1.0E-01	2.0E-04	E	9.0E-03	1.8E-05	D	1.7E+01	3.4E-02	D
Cyclone/impingement									
Cyclone/venturi							1.3E+01	2.6E-02	C
Cyclone/venturi/ impingement							8.1E+00	1.6E-02	E
Electrostatic precipitator	7.4E+00	1.5E-02	E				1.7E-01	3.4E-04	E
Fabric filter	4.0E-03	8.0E-06	E				1.0E-02	2.0E-05	E
Impingement							1.2E+00	2.4E-03	E
Venturi							1.1E-01	2.2E-04	E
Venturi/impingement/ afterburner							3.0E+00	6.0E-03	E
Venturi/impingement	3.2E+00	6.4E-03	D	5.0E-03	1.0E-05	E	3.3E+00	6.6E-03	E
Venturi/impingement/ WESP							1.0E-01	2.0E-04	E
Venturi/WESP							4.0E-02	8.0E-05	E

Table 2.5-5. (Continued)

Source Category[b]	Calcium			Chromium[c]			Cobalt[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	7.0E+02	1.4E+00	C	1.4E+01	2.9E-02	B	9.0E-01	1.8E-03	C
Controlled									
Cyclone	1.2E+00	2.4E-03	E	1.9E+00	3.8E-03	D	2.0E-01	4.0E-04	E
Cyclone/impingement				4.0E-02	8.0E-05	E			
Cyclone/venturi				5.0E-01	1.0E-03	E			
Cyclone/venturi/ impingement				1.1E+01	2.7E-02	E			
Electrostatic precipitator	3.5E+02	7.0E-01	E	1.4E+00	2.8E-03	E	3.8E-01	7.6E-04	E
Fabric filter	8.0E-02	1.6E-04	E	4.0E-02	8.0E-05	E	6.0E-03	1.2E-05	E
Impingement				9.8E+00	1.9E-02	E			
Venturi				5.0E-01	1.0E-03	E			
Venturi/impingement/ afterburner				4.9E+00	9.8E-03	E			
Venturi/impingement	2.6E+02	5.2E-01	D	2.1E+00	4.2E-03	E	4.5E-01	9.0E-04	D
Venturi/impingement/ WESP				1.1E-01	2.2E-04	E			
Venturi/WESP				1.0E-02	2.0E-05	E			

Table 2.5-5. (Continued)

Source Category[b]	Copper			Gold			Iron		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	4.0E+01	8.0E-02	B	3.0E-02	6.0E-05	E	5.6E+02	1.1E+00	C
Controlled									
Cyclone	2.7E+00	5.4E-03	E				1.7E+00	3.4E-03	E
Cyclone/impingement									
Cyclone/venturi	1.0E+00	2.0E-03	E						
Cyclone/venturi/ impingement									
Electrostatic precipitator	2.0E-01	4.0E-04	E	9.0E-03	1.8E-05	E	2.5E+01	5.0E-02	E
Fabric filter	2.0E-03	4.0E-06	E	2.0E-03	4.0E-06	E	2.3E-01	4.6E-04	E
Impingement									
Venturi	4.0E-01	8.0E-04	E						
Venturi/impingement/ afterburner	5.8E+00	1.2E-02	E						
Venturi/impingement	5.5E+00	1.1E-02	D	1.0E-02	2.0E-05	E	4.8E+01	9.6E-02	D
Venturi/impingement/ WESP									
Venturi/WESP	1.0E-02	2.0E-05	E						

Table 2.5-5. (Continued)

Source Category[b]	Manganese[c]			Magnesium			Mercury[c]		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	9.4E+00	1.9E-02	C	1.4E+02	2.8E-01	C			
Controlled									
Cyclone	3.3E-01	6.6E-04	E	1.4E+00	2.8E-03	E	2.3E+00	4.6E-03	E
Cyclone/impingement									
Cyclone/venturi							1.6E+00	3.2E-03	E
Cyclone/venturi/ impingement									
Electrostatic precipitator	3.2E-01	6.4E-04	E	8.8E+00	1.8E-02	E			
Fabric filter	5.0E-03	1.0E-05	E	3.0E-02	6.0E-05	E			
Impingement							9.7E-01	1.9E-03	E
Venturi									
Venturi/impingement/ afterburner									
Venturi/impingement	8.5E-01	1.7E-03	D	4.2E+00	8.4E-03	D	5.0E-03	1.0E-05	E
Venturi/impingement/ WESP									
Venturi/WESP									

Table 2.5-5. (Continued)

Source Category[b]	Nickel[c]			Phosphorus[c]			Potassium		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	8.0E+00	1.6E-02	B	3.8E+02	7.6E-01	D	5.3E+01	1.1E-01	E
Controlled									
Cyclone	8.0E-02	1.6E-04	E	8.9E+00	1.8E-02	E	9.0E-01	1.8E-03	E
Cyclone/impingement	1.3E+00	2.6E-03	D						
Cyclone/venturi	3.5E-01	7.0E-04	E						
Cyclone/venturi/ impingement	4.5E+00	9.0E-03	E						
Electrostatic precipitator	2.0E+00	4.0E-03	E	6.9E+00	1.4E-02	E			
Fabric filter	1.4E-02	2.8E-05	E	2.0E-01		E			
Impingement	4.1E+00	8.2E-03	E						
Venturi	6.0E-02	1.2E-04	E	9.6E-01	1.9E-03	E			
Venturi/impingement/ afterburner	9.0E-01	1.8E-03	E						
Venturi/impingement	9.0E-01	1.8E-03	A	1.2E+01	2.4E-02	D	7.3E+00	1.4E-02	E
Venturi/impingement/ WESP									
Venturi/WESP	3.0E-03	6.0E-06	E						

Table 2.5-5. (Continued)

Source Category[b]	Selenium[c]			Silicon			Silver		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	1.5E-01	3.0E-04	D	3.4E+02	6.8E-01	E	6.5E-01	1.3E-03	E
Controlled									
Cyclone				4.6E+00	9.2E-03	E			
Cyclone/impingement									
Cyclone/venturi									
Cyclone/venturi/ impingement									
Electrostatic precipitator							6.0E-03	1.2E-05	E
Fabric filter	1.2E-01	2.4E-04	E				1.0E-04	2.0E-07	E
Impingement									
Venturi	6.0E-02	1.2E-04	E				4.0E-01	8.0E-04	E
Venturi/impingement/ afterburner									
Venturi/impingement				4.4E+01	8.8E-02	E	9.0E-02	1.8E-04	E
Venturi/impingement/ WESP									
Venturi/WESP									

Table 2.5-5. (Continued)

Source Category[b]	Sodium			Sulfur			Tin		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	4.7E+01	9.4E-02	C	3.6E+03	7.2E+00	D	1.3E+01	2.6E-02	C
Controlled									
Cyclone	1.8E+00	3.6E-03	E	1.9E+01	3.9E-02	E	5.9E+00	1.2E-02	E
Cyclone/impingement									
Cyclone/venturi									
Cyclone/venturi/ impingement									
Electrostatic precipitator	5.5E-01	1.1E-03	E				2.0E-01	4.0E-04	E
Fabric filter	1.0E-02	2.0E-05	E	6.0E+01	1.2E-01	E	2.0E-02	4.0E-05	E
Impingement									
Venturi									
Venturi/impingement/ afterburner									
Venturi/impingement	1.4E+01	2.8E-02	D	1.1E+02	2.2E-01	E	7.9E+00	1.6E-02	D
Venturi/impingement/ WESP									
Venturi/WESP									

Table 2.5-5. (Continued)

Source Category[b]	Titanium			Vanadium			Zinc		
	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating	g/Mg	lb/ton	Emission Factor Rating
Uncontrolled	5.1E+01	1.0E-01	C	3.3E+00	6.6E-03	C	6.6E+01	1.3E-01	C
Controlled							1.1E+01	2.2E-02	E
Cyclone	1.0E-01	2.0E-04	E	3.0E-01	6.0E-04	E			
Cyclone/impingement									
Cyclone/venturi							3.8E+01	7.6E-02	E
Cyclone/venturi/ impingement									
Electrostatic precipitator	9.0E-01	1.8E-03	E	9.9E-01	2.0E-03	E	3.9E-01	7.8E-04	E
Fabric filter	6.0E-03	1.2E-05	E	2.0E-03	4.0E-06	E	4.0E-02	8.0E-05	E
Impingement									
Venturi							4.4E+00	8.8E-03	E
Venturi/impingement/ afterburner							3.3E+01	6.6E-02	E
Venturi/impingement	3.1E+00	6.2E-03	D	8.0E-01	1.6E-03	E	2.4E+01	4.8E-02	C
Venturi/impingement/ WESP									
Venturi/WESP							2.0E-01	4.0E-04	E

[a] Units are pollutants emitted of dry sludge burned. SCC = Source Classification Code.
[b] WESP = Wet Electrostatic Precipitator.
[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.5-6 (Metric and English Units). CRITERIA POLLUTANT EMISSION FACTORS FOR FLUIDIZED BED SEWAGE SLUDGE INCINERATORS[a]
(SCC 50100516)

EMISSION FACTOR RATING: E

Source Category[b]	Particulate Matter		Sulfur Dioxide		Nitrogen Oxides	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
Uncontrolled	2.3E+02	4.6E+02	1.5E-01	3.0E-01	4.0E-02	8.0E-02
Controlled						
Cyclone						
Cyclone/impingement						
Cyclone/venturi						
Cyclone/venturi/ impingement	5.0E-01	1.0E+00				
Electrostatic precipitator						
Fabric filter						
Impingement	1.3E-01	2.6E-01	3.0E-01	6.0E-01		
Venturi	5.7E-01		9.2E+00	1.8E+01	2.9E+00	5.8E+00
Venturi/impingement/ afterburner						
Venturi/impingement	2.7E-01	1.1E+00	4.0E-01	8.0E-01	5.0E-01	1.0E+00
Venturi/impingement/ WESP	1.0E-01	2.0E-01				
Venturi/WESP						

Table 2.5-6. (Continued)

Source Category[b]	Carbon Monoxide (CO)		Lead[c]		Methane VOC	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
Uncontrolled	5.0E-03	1.0E-02	2.0E-02	4.0E-02		
Controlled						
Cyclone						
Cyclone/impingement						
Cyclone/venturi						
Cyclone/venturi/ impingement						
Electrostatic precipitator						
Fabric filter			5.0E-06	1.0E-05		
Impingement			3.0E-03	6.0E-03		
Venturi					1.6E+00	3.2E+00
Venturi/impingement/ afterburner						
Venturi/impingement	1.1E+00	2.2E+00	8.0E-02	1.6E-01	4.0E-01	8.0E-01
Venturi/impingement/ WESP			1.0E-06	2.0E-06		
Venturi/WESP						

[a] Units are pollutants emitted of dry sludge burned. SCC = Source Classification Code.
[b] WESP = Wet Electrostatic Precipitator.
[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.5-7 (Metric and English Units). ACID GAS AND ORGANIC COMPOUND EMISSION FACTORS FOR FLUIDIZED BED SEWAGE SLUDGE INCINERATORS[a]
(SCC 50100516)

EMISSION FACTOR RATING: E

Pollutant	Uncontrolled		Impingement		Venturi/impingement		Cyclone/impingement	
	g/Mg	lb/ton	g/Mg	lb/ton	g/Mg	lb/ton	g/Mg	lb/ton
Sulfuric Acid (H_2SO_4)			3.0E+01	6.0E-02	6.0E+01	1.2E-01		
Hydrogen Chloride (HCl)[b]					5.0E+01	1.0E-01		
2,3,7,8-TCDD[b]					3.0E-07	6.0E-10		
Total TCDD					2.2E-06	4.4E-09		
Total PCDD	1.1E-06	2.2E-09						
Total HxCDD					9.0E-07	1.8E-09		
Total HpCDD					9.0E-07	1.8E-09		
Total OCDD					4.3E-06	8.6E-09		
2,3,7,8-TCDF[b]					2.0E-07	4.0E-10		
Total TCDF[b]					6.2E-06	1.2E-08		
Total PCDF[b]					5.2E-06	1.0E-08		
Total HxCDF[b]					4.1E-06	8.2E-09		
Total HpCDF[b]					1.6E-06	3.2E-09		
Total OCDF[b]					1.3E-06	2.6E-09		
1,1,1-Trichloroethane[b]					2.6E-01	5.2E-04		
1,2-Dichlorobenzene					6.4E+01	1.3E-01		
1,4-Dichlorobenzene[b]					2.4E+02	4.8E-01		
Benzene[b]					2.0E-01	4.0E-04		
Bis (2-ethylhexyl) phthalate[b]					4.1E+01	8.2E-02		
Carbon Tetrachloride[b]					1.2E-02	2.4E-05		

Table 2.5-7. (Continued)

Pollutant	Uncontrolled		Impingement		Venturi/impingement		Cyclone/impingement	
	g/Mg	lb/ton	g/Mg	lb/ton	g/Mg	lb/ton	g/Mg	lb/ton
Chlorobenzene[b]					5.0E-03	1.0E-05		
Chloroform[b]					2.0E+00	4.0E-03		
Ethylbenzene[b]					2.5E-02	5.0E-05		
Methylene Chloride[b]					7.0E-01	1.4E-03		
Naphthalene[b]					9.7E+01	1.9E-01		
Perchloroethylene[b]					1.2E-01	2.4E-04		
Toluene[b]							3.5E-01	7.0E-04
Trichloroethene[b]					3.0E-02	6.0E-05		

[a] Units are pollutants emitted of dry sludge burned. SCC = Source Classification Code.
[b] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.5-8 (Metric and English Units). METALS EMISSION FACTORS FOR FLUIDIZED BED SEWAGE SLUDGE INCINERATORS[a] (SCC 50100516)

EMISSION FACTOR RATING: E

Pollutant	Uncontrolled		Impingement		Venturi/impingement		Venturi/impingment/WESP	
	g/Mg	lb/ton	g/Mg	lb/ton	g/Mg	lb/ton	g/Mg	lb/ton
Aluminum					1.9E+00	3.8E-03		
Arsenic[c]	2.2E+00	4.4E-03			1.5E-02	3.0E-05	5.0E-03	1.0E-05
Barium					2.4E-01	4.8E-04		
Beryllium[c]					2.0E-04	4.0E-07	2.0E-04	4.0E-07
Cadmium[c]	2.2E+00	4.4E-03	4.0E-01	8.0E-04	5.7E-01	1.1E-03	1.0E-03	2.0E-06
Calcium[c]					5.2E+00	1.0E-02		
Chromium[c]			3.2E-01	6.4E-04	2.5E-01	5.0E-04	3.0E-02	6.0E-05
Copper					3.0E-01	6.0E-04		
Manganese[c]					3.0E-01	6.0E-04		
Magnesium					6.0E-01	1.2E-03		
Mercury[c]					3.0E-02	6.0E-05		
Nickel[c]	1.78E+01	3.5E-02			1.7E+00	3.4E-03	5.0E-03	1.0E-05
Potassium					6.0E-01	1.2E-03		
Selenium[c]					2.0E-01	4.0E-04		
Silicon					3.2E+00	6.4E-03		
Sulfur					8.6E+00	1.7E-02		

Table 2.5-8. (Continued)

Pollutant	Uncontrolled		Impingement		Venturi/impingement		Venturi/impingment/WESP	
	g/Mg	lb/ton	g/Mg	lb/ton	g/Mg	lb/ton	g/Mg	lb/ton
Tin					3.5E-01	7.0E-04		
Titanium					4.0E-01	8.0E-04		
Zinc					1.0E+00	2.0E-03		

[a] Units are pollutants emitted of dry sludge burned. SCC = Source Classification Code.
[b] WESP = Wet Electrostatic Precipitator.
[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.5-9 (Metric and English Units). SUMMARY OF EMISSION FACTORS FOR ELECTRIC INFRARED SEWAGE SLUDGE INCINERATORS[a]
(SCC 50100517)

EMISSION FACTOR RATING: E

Source Category[b]	Particulate Matter		Sulfur Dioxide		Nitrogen Oxides	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
Uncontrolled	3.7E+00	7.4E+00	9.2E+00	1.8E+01	4.3E+00	8.6E+00
Controlled						
Cyclone						
Cyclone/impingement						
Cyclone/venturi	1.9E+00	3.8E+00				
Cyclone/venturi/ impingement						
Electrostatic precipitator						
Fabric filter						
Impingement	8.2E-01	1.6E+00				
Venturi						
Venturi/impingement/ afterburner						
Venturi/impingement	9.5E-01	1.9E+00	2.3E+00	4.6E+00	2.9E+00	5.8E+00
Venturi/impingement/ WESP						
Venturi/WESP						

[a] Units are pollutants emitted of dry sludge burned. SCC = Source Classification Code.
[b] WESP = Wet Electrostatic Precipitator.

Table 2.5-10 (Metric and English Units). CUMULATIVE PARTICLE SIZE DISTRIBUTION FOR SEWAGE SLUDGE INCINERATORS[a]

EMISSION FACTOR RATING: E

Particle Size, Microns	Cumulative mass % stated size				
	Uncontrolled		Controlled (Scrubber)		
	MH[b]	EI[c]	MH	FB[d]	EI
15	15	43	30	7.7	60
10	10	30	27	7.3	50
5.0	5.3	17	25	6.7	35
2.5	2.8	10	22	6.0	25
1.0	1.2	6.0	20	5.0	18
0.625	0.75	5.0	17	2.7	15

[a] Reference 5.
[b] MH = multiple hearth incinerator. Source Classification Code (SCC) 50100515.
[c] EI = electric infrared incinerator. SCC 50100517.
[d] FB = fluidized bed incinerator. SCC 50100516.

Table 2.5-11 (Metric and English Units). CUMULATIVE PARTICLE SIZE-SPECIFIC EMISSION FACTORS FOR SEWAGE SLUDGE INCINERATORS[a]

EMISSION FACTOR RATING: E

Particle Size, Microns	Cumulative emission factor									
	Uncontrolled				Controlled (Scrubber)					
	MH[b]		EI[c]		MH		FB[d]		EI	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
15	6.0E+00	1.2E+01	4.3E+00	8.6E+00	1.2E-01	2.4E-01	2.3E-01	4.6E-01	1.2E+00	2.4E+00
10	4.1E+00	8.2E+00	3.0E+00	6.0E+00	1.1E-01	2.2E-01	2.2E-01	4.4E-01	1.0E+00	2.0E+00
5.0	2.1E+00	4.2E+00	1.7E+00	3.4E+00	1.0E-01	2.0E-01	2.0E-01	4.0E-01	7.0E-01	1.4E+00
2.5	1.1E+00	2.2E+00	1.0E+00	2.0E+00	9.0E-02	1.8E-01	1.8E-01	3.6E-01	5.0E-01	1.0E+00
1.0	4.7E-01	9.4E-01	6.0E-01	1.2E+00	8.0E-02	1.6E-01	1.5E-01	3.0E-01	3.5E-01	7.0E-01
0.625	3.0E-01	6.0E-01	5.0E-01	1.0E+00	7.0E-02	1.4E-01	8.0E-02	1.6E-01	3.0E-01	6.0E-01

[a]Reference 5.
[b]MH = multiple hearth incinerator. Source Classification Code (SCC) 50100515.
[c]EI = electric infrared incinerator. SCC 50100517.
[d]FB = fluidized bed incinerator. SCC 50100516.

Figure 2.5-4. Cumulative Particle Size Distribution and Size-Specific Emission Factors for Multiple-Health Incinerators

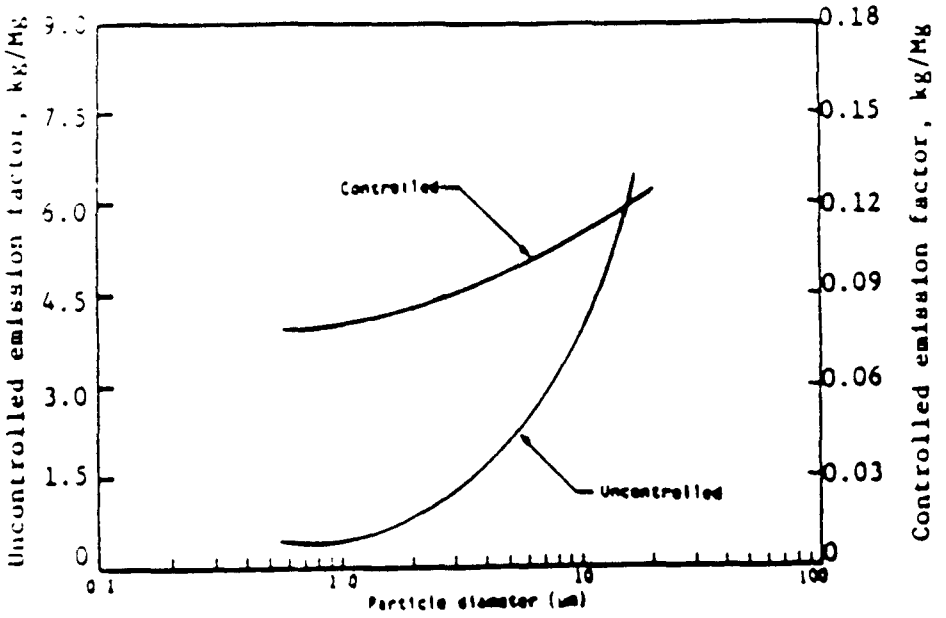


Figure 2.5-5. Cumulative Particle Size Distribution and Size-Specific Emission Factors for Fluidized-Bed Incinerators

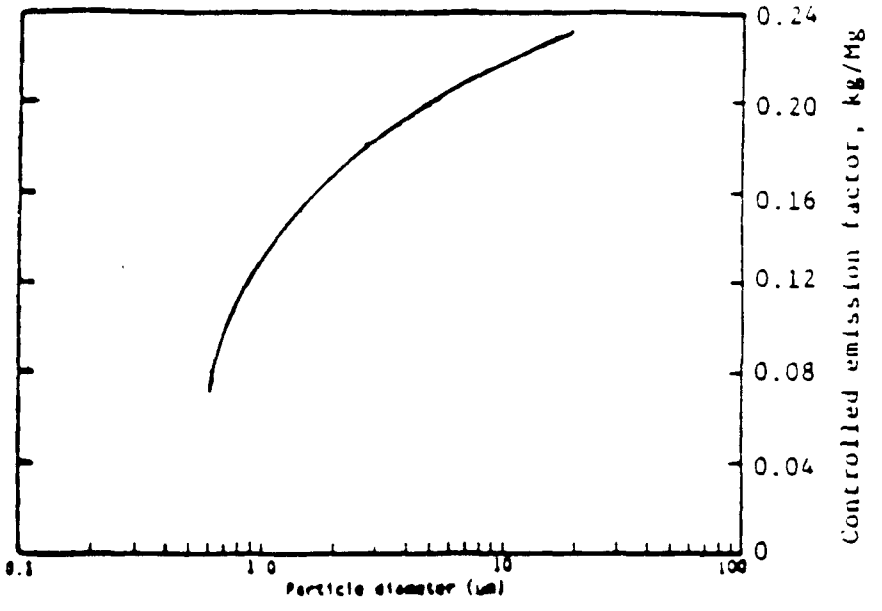
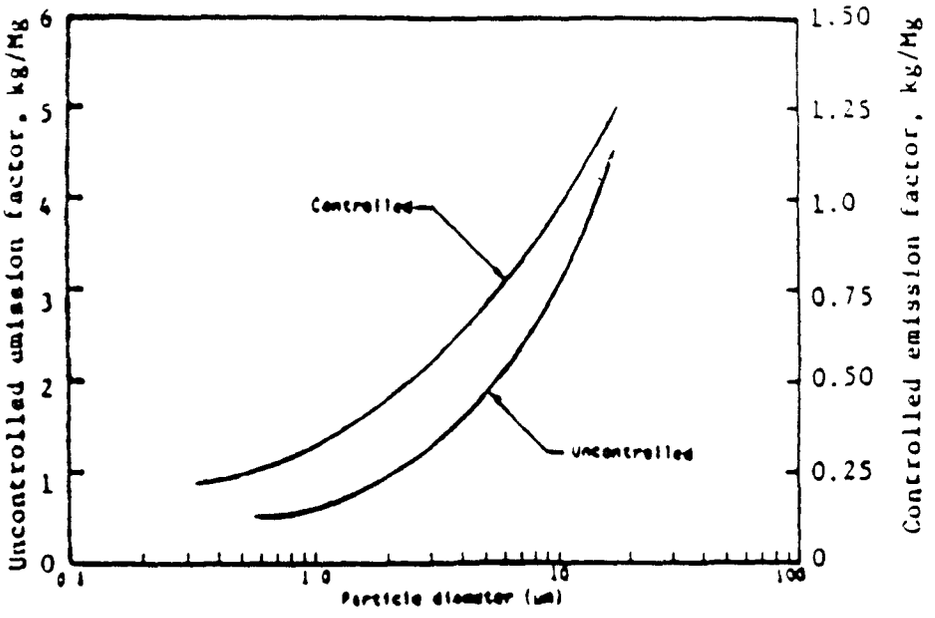


Figure 2.5-6. Cumulative Particle Size Distribution and Size-Specific Emission Factors for Electric (infrared) Incinerators



References for Section 2.5

1. *Second Review of Standards of Performance for Sewage Sludge Incinerators*, EPA-450/3-84-010, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, March 1984.

2. *Process Design Manual for Sludge Treatment and Disposal*, EPA-625/1-79-011, U. S. Environmental Protection Agency, Cincinnati, Ohio, September 1979.

3. *Control Techniques for Particulate Emissions From Stationary Sources - Volume 1*, EPA-450/3-81-005a, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, September 1982.

4. *Final Draft Test Report--Site 01 Sewage Sludge Incinerator SSI-A*, National Dioxin Study. Tier 4: Combustion Sources. EPA Contract No. 68-03-3148, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1986.

5. *Final Draft Test Report--Site 03 Sewage Sludge Incinerator SSI-B*, National Dioxin Study. Tier 4: Combustion Sources. EPA Contract No. 68-03-3148, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, July 1986.

6. *Draft Test Report--Site 12 Sewage Sludge Incinerator SSI-C*, EPA Contract No. 68-03-3138, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, April 1986.

7. M. Trichon and R. T. Dewling, *The Fate of Trace Metals in a Fluidized-Bed Sewage Sludge Incinerator*, (Port Washington). (GCA).

8. Engineering-Science, Inc., *Particulate and Gaseous Emission Tests at Municipal Sludge Incinerator Plants "O", "P", "Q", and "R" (4 tests)*, EPA Contract No. 68-02-2815, U. S. Environmental Protection Agency, McLean, Virginia, February 1980.

9. *Organics Screening Study Test Report. Sewage Sludge Incinerator No. 13, Detroit Water and Sewer Department, Detroit, Michigan*, EPA Contract No. 68-02-3849, PEI Associates, Inc., Cincinnati, Ohio, August 1986.

10. *Chromium Screening Study Test Report. Sewage Sludge Incinerator No. 13, Detroit Water and Sewer Department, Detroit Michigan*, EPA Contract No. 68-02-3849, PEI Associates, Inc., Cincinnati, Ohio, August 1986.

11. *Results of the October 24, 1980, Particulate Compliance Test on the No. 1 Sludge Incinerator Wet Scrubber Stack, MWCC St. Paul Wastewater Treatment Plant in St. Paul, Minnesota*, [STAPPA/ALAPCO/05/27/86-No. 02], Interpoll Inc., Circle Pines, Minnesota, November 1980.

12. *Results of the June 6, 1983, Emission Compliance Test on the No. 10 Incinerator System in the F&I 2 Building, MWCC Metro Plant, St. Paul, Minnesota*, [STAPPA/ALAPCO/05/27/86-No. 02], Interpoll Inc., Circle Pines, Minnesota, June 1983.

13. *Results of the May 23, 1983, Emission Compliance Test on the No. 9 Incinerator System in the F&I 2 Building, MWCC Metro Plant, St. Paul, Minnesota*, [STAPPA/ALAPCO/05/27/86-No. 02], Interpoll Inc., Circle Pines, Minnesota, May 1983.

14. *Results of the November 25, 1980, Particulate Emission Compliance Test on the No. 4 Sludge Incinerator Wet Scrubber Stack, MWCC St. Paul Wastewater Treatment Plant, St. Paul, Minnesota*, [STAPPA/ALAPCO/05/27/86-No. 02], Interpoll Inc., Circle Pines, Minnesota, December, 1980.

15. *Results of the March 28, 1983, Particulate Emission Compliance Test on the No. 8 Incinerator, MWCC Metro Plant, St. Paul, Minnesota*, [STAPPA/ALAPCO/05/28/86-No. 06], Interpoll Inc., Circle Pines, Minnesota, April 1983.

16. *Particulate Emission Test Report for a Sewage Sludge Incinerator, City of Shelby Wastewater Treatment Plant*, [STAPPA/ALAPCO/07/28/86-No. 06], North Carolina Department of Natural Resources, February 1979.

17. *Source Sampling Evaluation for Rocky River Wastewater Treatment Plant, Concord, North Carolina*, [STAPPA/ALAPCO/05/28/86-No. 06], Mogul Corp., Charlotte, North Carolina, July 1982.

18. *Performance Test Report: Rocky Mount Wastewater Treatment Facility*, [STAPPA/ALAPCO/07/28/86-No. 06], Envirotech, Belmont, California, July 1983.

19. *Performance Test Report for the Incineration System at the Honolulu Wastewater Treatment Plant, Honolulu, Oahu, Hawaii*, [STAPPA/ALAPCO/05/22/86-No. 11], Zimpro, Rothschild, Wisconsin, January 1984.

20. *(Test Results) Honolulu Wastewater Treatment Plant, Ewa, Hawaii*, [STAPPA/ALAPCO/05/22/86-No. 11], Zimpro, Rothschild, Wisconsin, November 1983.

21. *Air Pollution Source Test. Sampling and Analysis of Air Pollutant Effluent from Wastewater Treatment Facility--Sand Island Wastewater Treatment Plant in Honolulu, Hawaii*, [STAPPA/ALAPCO/05/22/86-No. 11], Ultrachem, Walnut Creek, California, December 1978.

22. *Air Pollution Source Test. Sampling and Analysis of Air Pollutant Effluent From Wastewater Treatment Facility--Sand Island Wastewater Treatment Plant in Honolulu, Hawaii--Phase II*, [STAPPA/ALAPCO/05/22/86-No. 11], Ultrachem, Walnut Creek, California, December 1979.

23. *Stationary Source Sampling Report, EEI Reference No. 2988, at the Osborne Wastewater Treatment Plant, Greensboro, North Carolina*, [STAPPA/ALAPCO/07/28/86-No. 06], Particulate Emissions and Particle Size Distribution Testing. Sludge Incinerator Scrubber Inlet and Scrubber Stack, Entropy, Research Triangle Park, North Carolina, October 1985.

24. *Metropolitan Sewer District--Little Miami Treatment Plant (three tests: August 9, 1985, September 16, 1980, and September 30, 1980) and Mill Creek Treatment Plant (one test: January 9, 1986)*, [STAPPA/ALAPCO/05/28/86-No. 14], Southwestern Ohio Air Pollution Control Agency.

25. *Particulate Emissions Compliance Testing, at the City of Milwaukee South Shore Treatment Plant, Milwaukee, Wisconsin*, [STAPPA/ALAPCO/06/12/86-No. 19], Entropy, Research Triangle Park, North Carolina, December 1980.

26. *Particulate Emissions Compliance Testing, at the City of Milwaukee South Shore Treatment Plant, Milwaukee, Wisconsin*, [STAPPA/ALAPCO/06/12/86-No. 19], Entropy, Research Triangle Park, North Carolina, November 1980.

27. *Stack Test Report--Bayshore Regional Sewage Authority, in Union Beach, New Jersey*, [STAPPA/ALAPCO/05/22/86-No. 12], New Jersey State Department of Environmental Protection, Trenton, New Jersey, March 1982.

28. *Stack Test Report--Jersey City Sewage Authority, in Jersey City, New Jersey*, [STAPPA/ALAPCO/05/22/86-No. 12], New Jersey State Department of Environmental Protection, Trenton, New Jersey, December 1980.

29. *Stack Test Report--Northwest Bergen County Sewer Authority, in Waldwick, New Jersey*, [STAPPA/ALAPCO/05/22/86-No. 12], New Jersey State Department of Environmental Protection, Trenton, New Jersey, March 1982.

30. *Stack Test Report--Pequannock, Lincoln Park, and Fairfield Sewerage Authority, in Lincoln Park, New Jersey*, [STAPPA/ALAPCO/05/22/86-No. 12], New Jersey State Department of Environmental Protection, Trenton, New Jersey, December 1975.

31. *Atmospheric Emission Evaluation, of the Anchorage Water and Wastewater Utility Sewage Sludge Incinerator*, ASA, Bellevue, Washington, April 1984.

32. *Stack Sampling Report for Municipal Sewage Sludge Incinerator No. 1, Scrubber Outlet (Stack), Providence, Rhode Island*, Recon Systems, Inc., Three Bridges, New Jersey, November 1980.

33. *Stack Sampling Report, Compliance Test No. 3, at the Attleboro Advanced Wastewater Treatment Facility, in Attleboro, Massachusetts*, David Gordon Associates, Inc., Newton Upper Falls, Massachusetts, May 1983.

34. *Source Emission Survey, at the Rowlett Creek Plant*, North Texas Municipal Water District, Plano, Texas, Shirco, Inc., Dallas, Texas, November 1978.

35. *Emissions Data for Infrared Municipal Sewage Sludge Incinerators (Five tests)*, Shirco, Inc., Dallas, Texas, January 1980.

37. *Electrostatic Precipitator Efficiency on a Multiple Hearth Incinerator Burning Sewage Sludge*, Contract No. 68-03-3148, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, August 1986.

38. *Baghouse Efficiency on a Multiple Hearth Incinerator Burning Sewage Sludge*, Contract No. 68-03-3148, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, August 1986.

39. J.B. Farrell and H. Wall, *Air Pollution Discharges from Ten Sewage Sludge Incinerators*, U. S. Environmental Protection Agency, Cincinnati, Ohio, August 1985.

40. *Emission Test Report. Sewage Sludge Incinerator, at the Davenport Wastewater Treatment Plant, Davenport, Iowa*, [STAPPA/ALAPCO/11/04/86-No. 119], PEDCo Environmental, Cincinnati, Ohio, October 1977.

41. *Sludge Incinerator Emission Testing. Unit No. 1 for City of Omaha, Papillion Creek Water Pollution Control Plant*, [STAPPA/ALAPCO/10/28/86-No. 100], Particle Data Labs, Ltd., Elmhurst, Illinois, September 1978.

42. *Sludge Incinerator Emission Testing. Unit No. 2 for City of Omaha, Papillion Creek Water Pollution Control Plant*, [STAPPA/ALAPCO/10/28/86-No. 100], Particle Data Labs, Ltd., Elmhurst, Illinois, May 1980.

43. *Particulate and Sulfur Dioxide Emissions Test Report for Zimpro on the Sewage Sludge Incinerator Stack at the Cedar Rapids Water Pollution Control Facility*, [STAPPA/ALAPCO/11/04/86-No. 119], Serco, Cedar Falls, Iowa, September 1980.

44. *Newport Wastewater Treatment Plant*, Newport, Tennessee. (Nichols; December 1979). [STAPPA/ALAPCO/10/27/86-No. 21].

45. *Maryville Wastewater Treatment Plant Sewage Sludge Incinerator Emission Test Report*, [STAPPA/ALAPCO/10/27/86-No. 21], Enviro-measure, Inc., Knoxville, Tennessee, August 1984.

46. *Maryville Wastewater Treatment Plant Sewage Sludge Incinerator Emission Test Report*, [STAPPA/ALAPCO/10/27/86-No. 21], Enviro-measure, Inc., Knoxville, Tennessee, October 1982.

47. *Southerly Wastewater Treatment Plant, Cleveland, Ohio, Incinerator No. 3*, [STAPPA/ALAPCO/11/12/86-No. 124], Envisage Environmental, Inc., Richfield, Ohio, May 1985.

48. *Southerly Wastewater Treatment Plant, Cleveland, Ohio. Incinerator No. 1*, [STAPPA/ALAPCO/11/12/86-No. 124], Envisage Environmental, Inc., Richfield, Ohio, August 1985.

49. *Final Report for an Emission Compliance Test Program (July 1, 1982), at the City of Waterbury Wastewater Treatment Plant Sludge Incinerator, Waterbury, Connecticut*, [STAPPA/ALAPCO/12/17/86-No. 136], York Services Corp, July 1982.

50. *Incinerator Compliance Test, at the City of Stratford Sewage Treatment Plant, Stratford, Connecticut*, [STAPPA/ALAPCO/12/17/86-No. 136], Emission Testing Labs, September 1974.

51. *Emission Compliance Tests at the Norwalk Wastewater Treatment Plant in South Smith Street, Norwalk, Connecticut*, [STAPPA/ALAPCO/12/17/86-No. 136], York Research Corp, Stamford, Connecticut, February 1975.

52. *Final Report--Emission Compliance Test Program at the East Shore Wastewater Treatment Plant in New Haven, Connecticut*, [STAPPA/ALAPCO/12/17/86-No. 136], York Services Corp., Stamford, Connecticut, September 1982.

53. *Incinerator Compliance Test at the Enfield Sewage Treatment Plant in Enfield, Connecticut*, [STAPPA/ALAPCO/12/17/86-No. 136], York Research Corp., Stamford, Connecticut, July 1973.

54. *Incinerator Compliance Test at The Glastonbury Sewage Treatment Plant in Glastonbury, Connecticut*, [STAPPA/ALAPCO/12/17/86-No. 136], York Research Corp., Stamford, Connecticut, August 1973.

55. *Results of the May 5, 1981, Particulate Emission Measurements of the Sludge Incinerator, at the Metropolitan District Commission Incinerator Plant*, [STAPPA/ALAPCO/12/17/86-No. 136], Henry Souther Laboratories, Hartford, Connecticut.

56. *Official Air Pollution Tests Conducted on the Nichols Engineering and Research Corporation Sludge Incinerator at the Wastewater Treatment Plant in Middletown, Connecticut*, [STAPPA/ALAPCO/12/17/86-No. 136], Rossnagel and Associates, Cherry Hill, New Jersey, November 1976.

57. *Measured Emissions From the West Nichols-Neptune Multiple Hearth Sludge Incinerator at the Naugatuck Treatment Company in Naugatuck, Connecticut*, [STAPPA/ALAPCO/12/17/86-No. 136], The Research Corp., East Hartford, Connecticut, April 1985.

58. *Compliance Test Report--(August 27, 1986), at the Mattabasset District Pollution Control Plant Main Incinerator in Cromwell, Connecticut*, [STAPPA/ALAPCO/12/17/86-No. 136], ROJAC Environmental Services, Inc., West Hartford, Connecticut, September 1986.

59. *Stack Sampling Report (May 21, 1986) City of New London No. 2 Sludge Incinerator Outlet Stack Compliance Test*, [STAPPA/ALAPCO/12/17/86-No. 136], Recon Systems, Inc., Three Bridges, New Jersey, June 1986.

60. *Particulate Emission Tests, at the Town of Vernon Municipal Sludge Incinerator in Vernon, Connecticut*, [STAPPA/ALAPCO/12/17/86-No. 136], The Research Corp., Wethersfield, Connecticut, March 1981.

61. *Non-Criteria Emissions Monitoring Program for the Envirotech Nine- Hearth Sewage Sludge Incinerator, at the Metropolitan Wastewater Treatment Facility in St. Paul, Minnesota*, ERT Document No. P-E081-500, October 1986.

62. D.R. Knisley, *et al., Site 1 Revised Draft Emission Test Report, Sewage Sludge Test Program*, U. S. Environmental Protection Agency, Water Engineering Research Laboratory, Cincinnati, Ohio, February 9, 1989.

63. D.R. Knisley, *et al., Site 2 Final Emission Test Report, Sewage Sludge Test Program*, U. S. Environmental Protection Agency, Water Engineering Research Laboratory, Cincinnati, Ohio, October 19, 1987.

64. D.R. Knisley, *et al.*, *Site 3 Draft Emission Test Report and Addendum, Sewage Sludge Test Program. Volume 1: Emission Test Results*, U. S. Environmental Protection Agency, Water Engineering Research Laboratory, Cincinnati, Ohio, October 1, 1987.

65. D.R. Knisley, *et al.*, *Site 4 Final Emission Test Report, Sewage Sludge Test Program*, U. S. Environmental Protection Agency, Water Engineering Research Laboratory, Cincinnati, Ohio, May 9, 1988.

66. R.C. Adams, *et al.*, *Organic Emissions from the Exhaust Stack of a Multiple Hearth Furnace Burning Sewage Sludge*, U. S. Environmental Protection Agency, Water Engineering Research Laboratory, Cincinnati, Ohio, September 30, 1985.

67. R.C. Adams, *et al.*, *Particulate Removal Evaluation of an Electrostatic Precipitator Dust Removal System Installed on a Multiple Hearth Incinerator Burning Sewage Sludge*, U. S. Environmental Protection Agency, Water Engineering Research Laboratory, Cincinnati, Ohio, September 30, 1985.

68. R.C. Adams, *et al.*, *Particulate Removal Capability of a Baghouse Filter on the Exhaust of a Multiple Hearth Furnace Burning Sewage Sludge*, U. S. Environmental Protection Agency, Water Engineering Research Laboratory, Cincinnati, Ohio, September 30, 1985.

69. R.G. McInnes, *et al.*, *Sampling and Analysis Program at the New Bedford Municipal Sewage Sludge Incinerator*, GCA Corporation/Technology Division. U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, November 1984.

70. R.T. Dewling, *et al.*, "Fate and Behavior of Selected Heavy Metals in Incinerated Sludge." *Journal of the Water Pollution Control Federation*, Vol. 52, No. 10, October 1980.

71. R.L. Bennet, *et al.*, *Chemical and Physical Characterization of Municipal Sludge Incinerator Emissions*, Report No. EPA 600/3-84-047, NTIS No. PB 84-169325, U. S. Environmental Protection Agency, Environmental Sciences Research Laboratory, Research Triangle Park, North Carolina, March 1984.

72. Acurex Corporation. *1990 Source Test Data for the Sewage Sludge Incinerator*, Project 6595, Mountain View, California, April 15, 1991.

73. *Emissions of Metals, Chromium, and Nickel Species, and Organics from Municipal Wastewater Sludge Incinerators, Volume I: Summary Report*, U. S. Environmental Protection Agency, Cincinnati, Ohio, 1992.

74. L.T. Hentz, *et al.*, *Air Emission Studies of Sewage Sludge, Incinerators at the Western Branch Wastewater Treatment Plan*, Water Environmental Research, Vol. 64, No. 2, March/April, 1992.

75. *Source Emissions Testing of the Incinerator #2 Exhaust Stack at the Central Costa Sanitary District Municipal Wastewater Treatment Plan, Mortmez, California*, Galson Technical Services, Berkeley, California, October, 1990.

76. R.R. Segal, *et al., Emissions of Metals, Chromium and Nickel Species, and Organics from Municipal Wastewater Sludge Incinerators, Volume II: Site 5 Test Report - Hexavalent Chromium Method Evaluation*, EPA 600/R-92/003a, March 1992.

77. R.R. Segal, *et al., Emissions of Metals, Chromium and Nickel Species, and Organics from Municipal Wastewater Sludge Incinerators, Volume III: Site 6 Test Report*, EPA 600/R-92/003a, March 1992.

78. A.L. Cone *et al., Emissions of Metals, Chromium, Nickel Species, and Organics from Municipal Wastewater Sludge Incinerators. Volume 5: Site 7 Test Report CEMS*, Entropy Environmentalists, Inc., Research Triangle Park, North Carolina, March 1992.

79. R.R. Segal, *et al., Emissions of Metals, Chromium and Nickel Species, and Organics from Municipal Wastewater Sludge Incinerators, Volume VI: Site 8 Test Report*, EPA 600/R-92/003a, March 1992.

80. R.R. Segal, *et al., Emissions of Metals, Chromium and Nickel Species, and Organics from Municipal Wastewater Sludge Incinerators, Volume VII: Site 9 Test Report*, EPA 600/R-92/003a, March 1992.

81. *Stack Sampling for THC and Specific Organic Pollutants at MWCC Incinerators*. Prepared for the Metropolitan Waste Control Commission, Mears Park Centre, St. Paul, Minnesota, July 11, 1991, QC-91-217.

2.6 MEDICAL WASTE INCINERATION

Medical waste incineration involves the burning of wastes produced by hospitals, veterinary facilities, and medical research facilities. These wastes include both infectious ("red bag") medical wastes as well as non-infectious, general housekeeping wastes. The emission factors presented here represent emissions when both types of these wastes are combusted rather than just infectious wastes.

Three main types of incinerators are used: controlled air, excess air, and rotary kiln. Of the incinerators identified in this study, the majority (>95 percent) are controlled air units. A small percentage (<2 percent) are excess air. Less than one percent were identified as rotary kiln. The rotary kiln units tend to be larger, and typically are equipped with air pollution control devices. Approximately 2 percent of the total population identified in this study were found to be equipped with air pollution control devices.

2.6.1 Process Description[1-6]

Types of incineration described in this section include:

- Controlled air,
- Excess air, and
- Rotary kiln.

2.6.1.1 Controlled-Air Incinerators -- Controlled-air incineration is the most widely used medical waste incinerator (MWI) technology, and now dominates the market for new systems at hospitals and similar medical facilities. This technology is also known as starved-air incineration, two-stage incineration, or modular combustion. Figure 2.6-1 presents a typical schematic diagram of a controlled air unit.

Combustion of waste in controlled air incinerators occurs in two stages. In the first stage, waste is fed into the primary, or lower, combustion chamber, which is operated with less than the stoichiometric amount of air required for combustion. Combustion air enters the primary chamber from beneath the incinerator hearth (below the burning bed of waste). This air is called primary or underfire air. In the primary (starved-air) chamber, the low air-to-fuel ratio dries and facilitates volatilization of the waste, and most of the residual carbon in the ash burns. At these conditions, combustion gas temperatures are relatively low [760 to 980°C (1,400 to 1,800°F)].

In the second stage, excess air is added to the volatile gases formed in the primary chamber to complete combustion. Secondary chamber temperatures are higher than primary chamber temperatures--typically 980 to 1,095°C (1,800 to 2,000°F). Depending on the heating value and moisture content of the waste, additional heat may be needed. This can be provided by auxiliary burners located at the entrance to the secondary (upper) chamber to maintain desired temperatures.

Waste feed capacities for controlled air incinerators range from about 0.6 to 50 kg/min (75 to 6,500 lb/hr) [at an assumed fuel heating value of 19,700 kJ/kg (8,500 Btu/lb)]. Waste feed and ash removal can be manual or automatic, depending on the unit size and options purchased. Throughput

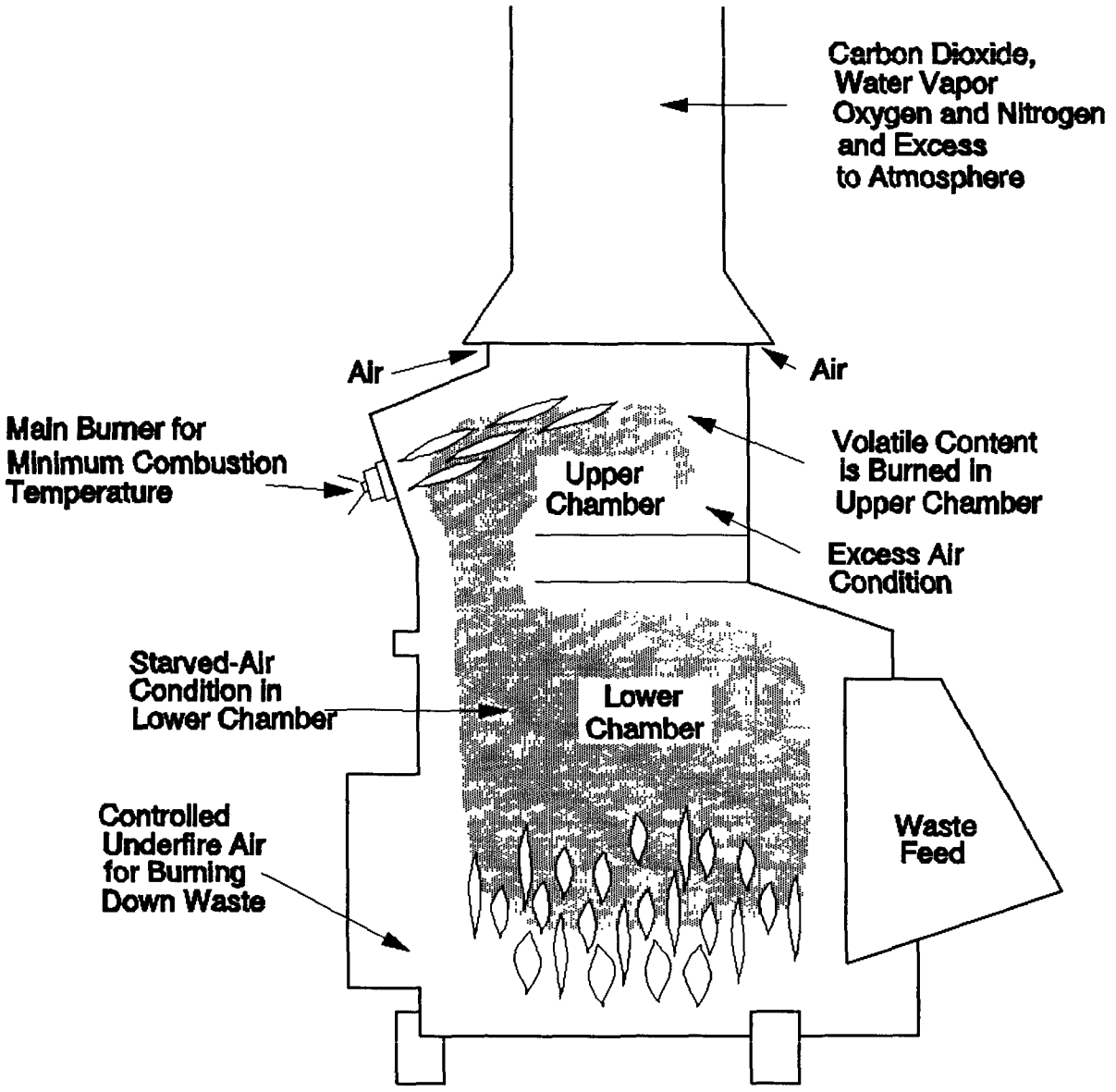


Figure 2.6-1. Controlled Air Incinerator

capacities for lower heating value wastes may be higher, since feed capacities are limited by primary chamber heat release rates. Heat release rates for controlled air incinerators typically range from about 430,000 to 710,000 kJ/hr-m^3 (15,000 to 25,000 Btu/hr-ft^3).

Because of the low air addition rates in the primary chamber, and corresponding low flue gas velocities (and turbulence), the amount of solids entrained in the gases leaving the primary chamber is low. Therefore, the majority of controlled air incinerators do not have add-on gas cleaning devices.

2.6.1.2 Excess Air Incinerators -- Excess air incinerators are typically small modular units. They are also referred to as batch incinerators, multiple chamber incinerators, or "retort" incinerators. Excess air incinerators are typically a compact cube with a series of internal chambers and baffles. Although they can be operated continuously, they are usually operated in a batch mode.

Figure 2.6-2 presents a schematic for an excess air unit. Typically, waste is manually fed into the combustion chamber. The charging door is then closed, and an afterburner is ignited to bring the secondary chamber to a target temperature [typically 870 to 980°C (1600 to 1800°F)]. When the target temperature is reached, the primary chamber burner ignites. The waste is dried, ignited, and combusted by heat provided by the primary chamber burner, as well as by radiant heat from the chamber walls. Moisture and volatile components in the waste are vaporized, and pass (along with combustion gases) out of the primary chamber and through a flame port which connects the primary chamber to the secondary or mixing chamber. Secondary air is added through the flame port and is mixed with the volatile components in the secondary chamber. Burners are also installed in the secondary chamber to maintain adequate temperatures for combustion of volatile gases. Gases exiting the secondary chamber are directed to the incinerator stack or to an air pollution-control device. When the waste is consumed, the primary burner shuts off. Typically, the afterburner shuts off after a set time. Once the chamber cools, ash is manually removed from the primary chamber floor and a new charge of waste can be added.

Incinerators designed to burn general hospital waste operate at excess air levels of up to 300 percent. If only pathological wastes are combusted, excess air levels near 100 percent are more common. The lower excess air helps maintain higher chamber temperature when burning high moisture waste. Waste feed capacities for excess air incinerators are usually 3.8 kg/min (500 lb/hr) or less.

2.6.1.3 Rotary Kiln Incinerators -- Rotary kiln incinerators, like the other types, are designed with a primary chamber, where the waste is heated and volatilized, and a secondary chamber, where combustion of the volatile fraction is completed. The primary chamber consists of a slightly inclined, rotating kiln in which waste materials migrate from the feed end to the ash discharge end. The waste throughput rate is controlled by adjusting the rate of kiln rotation and the angle of inclination. Combustion air enters the primary chamber through a port. An auxiliary burner is generally used to start combustion and maintain desired combustion temperatures. Both the primary and secondary chambers are usually lined with acid-resistant refractory brick, as shown in the schematic drawing, Figure 2.6-3.

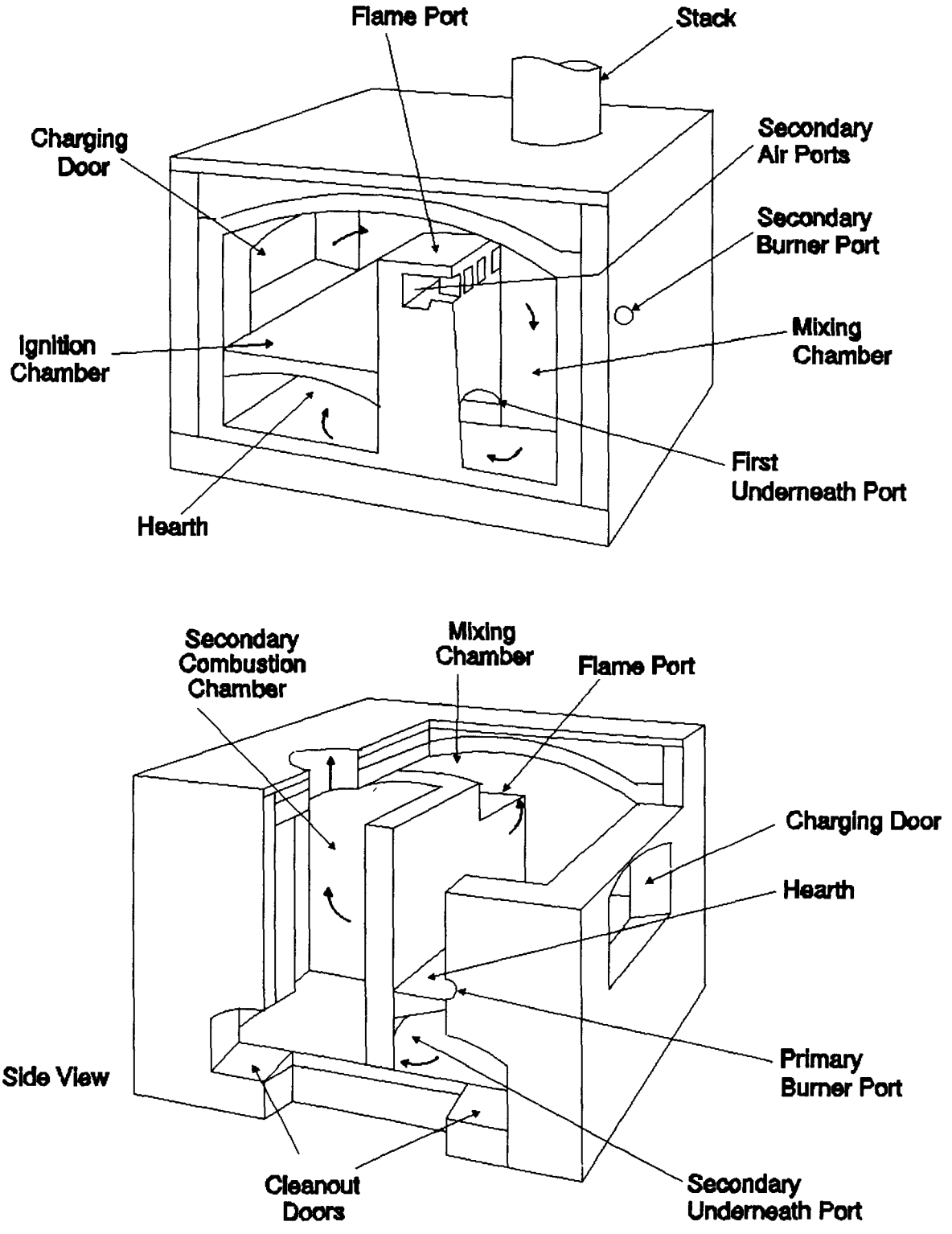


Figure 2.6-2. Excess Air Incinerator

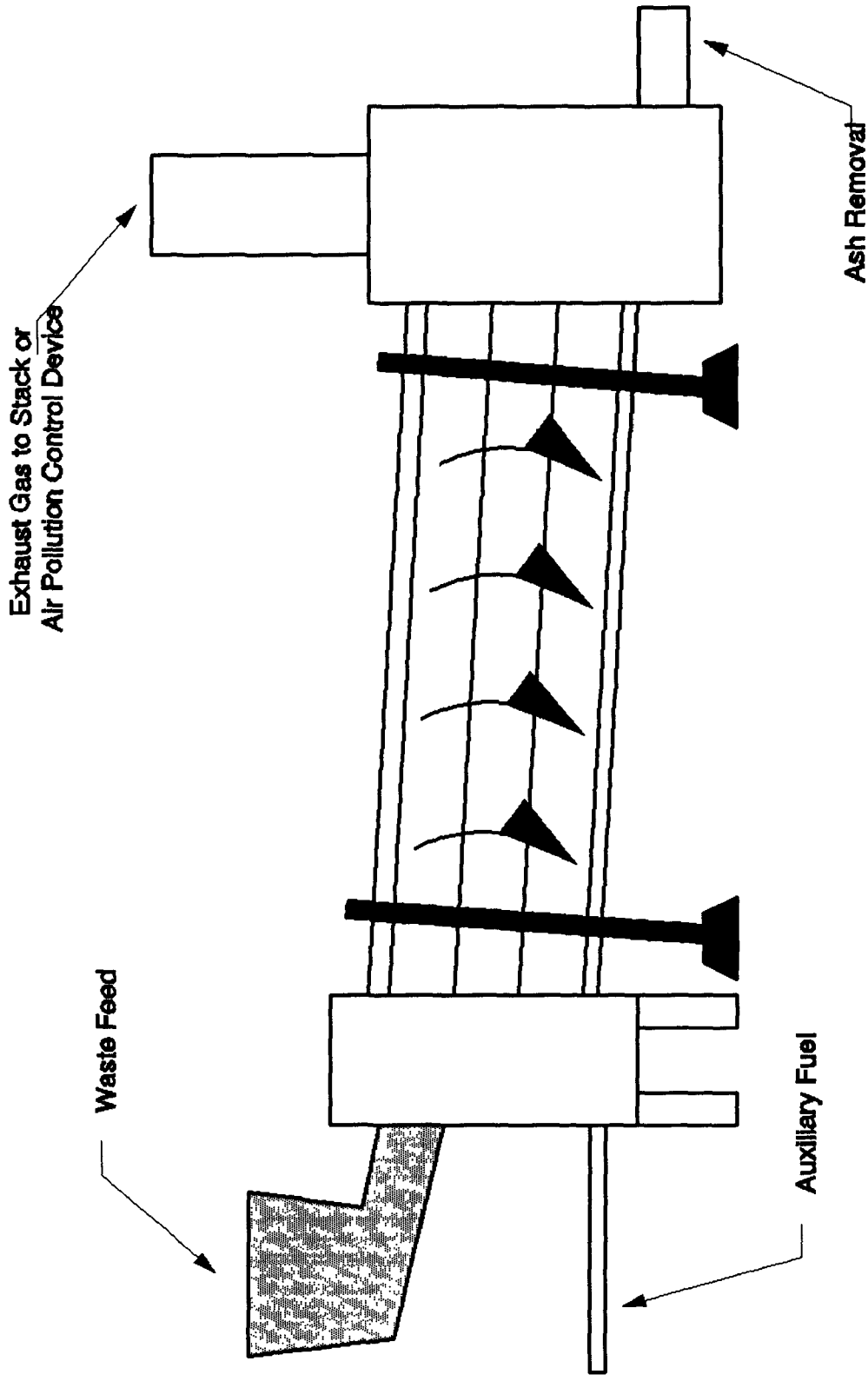


Figure 2.6-3. Rotary Kiln Incinerator

Volatiles and combustion gases pass from the primary chamber to the secondary chamber. The secondary chamber operates at excess air. Combustion of the volatiles is completed in the secondary chamber. Due to the turbulent motion of the waste in the primary chamber, solids burnout rates and particulate entrainment in the flue gas are higher for rotary kiln incinerators than for other incinerator designs. As a result, rotary kiln incinerators generally have add-on gas cleaning devices.

2.6.2 Emissions and Controls[2,4,7-43]

Medical waste incinerators can emit significant quantities of pollutants to the atmosphere. These pollutants include: 1) particulate matter (PM), 2) metals, 3) acid gases, 4) oxides of nitrogen (NO_x), 5) carbon monoxide (CO), 6) organics, and 7) various other materials present in medical wastes, such as pathogens, cytotoxins, and radioactive diagnostic materials.

Particulate matter is emitted as a result of incomplete combustion of organics (i.e., soot) and by the entrainment of noncombustible ash due to the turbulent movement of combustion gases. Particulate matter may exit as a solid or an aerosol, and may contain heavy metals, acids, and/or trace organics.

Uncontrolled particulate emission rates vary widely, depending on the type of incinerator, composition of the waste, and the operating practices employed. Entrainment of PM in the incinerator exhaust is primarily a function of the gas velocity within the combustion chamber containing the solid waste. Controlled air incinerators have the lowest turbulence and, consequently, lowest PM emissions; rotary kiln incinerators have highly turbulent combustion, and thus have the highest PM emissions.

The type and amount of trace metals in the flue gas are directly related to the metals contained in the waste. Metals emissions are affected by the level of PM control and the flue gas temperature. Most metals (except mercury) exhibit fine-particle enrichment and are removed by maximizing small particle collection. Mercury, due to its high vapor pressure, does not show significant particle enrichment, and removal is not a function of small particle collection in gas streams at temperatures greater than 150°C (300°F).

Acid gas concentrations of hydrogen chloride (HCl) and sulfur dioxide (SO_2) in MWI flue gases are directly related to the chlorine and sulfur content of the waste. Most of the chlorine, which is chemically bound within the waste in the form of polyvinyl chloride (PVC) and other chlorinated compounds, will be converted to HCl. Sulfur is also chemically bound within the materials making up medical waste and is oxidized during combustion to form SO_2.

Oxides of nitrogen (NO_x) represent a mixture of mainly nitric oxide (NO) and nitrogen dioxide (NO_2). They are formed during combustion by: 1) oxidation of nitrogen chemically bound in the waste, and 2) reaction between molecular nitrogen and oxygen in the combustion air. The formation of NO_x is dependent on the quantity of fuel-bound nitrogen compounds, flame temperature, and air/fuel ratio.

Carbon monoxide is a product of incomplete combustion. Its presence can be related to insufficient oxygen, combustion (residence) time, temperature, and turbulence (fuel/air mixing) in the combustion zone.

Failure to achieve complete combustion of organic materials evolved from the waste can result in emissions of a variety of organic compounds. The products of incomplete combustion (PICs) range

from low molecular weight hydrocarbon (e.g., methane or ethane) to high molecular weight compounds [e.g., polychlorinated dibenzo-p-dioxins and dibenzofurans (CDD/CDF)]. In general, combustion conditions required for control of CO (i.e., adequate oxygen, temperature, residence time, and turbulence) will also minimize emissions of most organics.

Emissions of CDD/CDF from MWIs may occur as either a vapor or as a fine particulate. Many factors are believed to be involved in the formation of CDD/CDF and many theories exist concerning the formation of these compounds. In brief, the best supported theories involve four mechanisms of formation.[2] The first theory states that trace quantities of CDD/CDF present in the refuse feed are carried over, unburned, to the exhaust. The second theory involves formation of CDD/CDF from chlorinated precursors with similar structures. Conversion of precursor material to CDD/CDF can potentially occur either in the combustor at relatively high temperatures or at lower temperatures such as are present in wet scrubbing systems. The third theory involves synthesis of CDD/CDF compounds from a variety of organics and a chlorine donor. The fourth mechanism involves catalyzed reactions on fly ash particles at low temperatures.

To date, most MWIs have operated without add-on air pollution control devices (APCDs). A small percentage (approximately 2 percent) of MWIs do use APCDs. The most frequently used control devices are wet scrubbers and fabric filters (FFs). Fabric filters provide mainly PM control. Other PM control technologies include venturi scrubbers and electrostatic precipitators (ESPs). In addition to wet scrubbing, dry sorbent injection (DSI) and spray dryer absorbers have also been used for acid gas control.

Wet scrubbers use gas-liquid absorption to transfer pollutants from a gas to a liquid stream. Scrubber design and the type of liquid solution used largely determine contaminant removal efficiencies. With plain water, removal efficiencies for acid gases could be as high as 70 percent for HCl and 30 percent for SO_2. Addition of an alkaline reagent to the scrubber liquor for acid neutralization has been shown to result in removal efficiencies of 93 to 96 percent.

Wet scrubbers are generally classified according to the energy required to overcome the pressure drop through the system. Low-energy scrubbers (spray towers) are primarily used for acid gas control only, and are usually circular in cross-section. The liquid is sprayed down the tower through the rising gas. Acid gases are absorbed/neutralized by the scrubbing liquid. Low energy scrubbers mainly remove particles larger than 5-10 micrometers (μm) in diameter.

Medium-energy scrubbers can be used for particulate matter and/or acid gas control. Medium energy devices rely mostly on impingement to facilitate removal of PM. This can be accomplished through a variety of configurations, such as packed columns, baffle plates, and liquid impingement scrubbers.

Venturi scrubbers are high-energy systems that are used primarily for PM control. A typical venturi scrubber consists of a converging and a diverging section connected by a throat section. A liquid (usually water) is introduced into the gas stream upstream of the throat. The flue gas impinges on the liquid stream in the converging section. As the gas passes through the throat, the shearing action atomizes the liquid into fine droplets. The gas then decelerates through the diverging section, resulting in further contact between particles and liquid droplets. The droplets are then removed from the gas stream by a cyclone, demister or swirl vanes.

A fabric filtration system (baghouse) consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure with dust hoppers. Particulate-laden

gas passes through the bags so that the particles are retained on the upstream side of the fabric, thus cleaning the gas. A FF is typically divided into several compartments or sections. In a FF, both the collection efficiency and the pressure drop across the bag surface increase as the dust layer on the bag builds up. Since the system cannot continue to operate with an increasing pressure drop, the bags are cleaned periodically. The cleaning processes include reverse flow with bag collapse, pulse jet cleaning, and mechanical shaking. When reverse flow and mechanical shaking are used, the particulate matter is collected on the inside of the bag; particulate matter is collected on the outside of the bag in pulse jet systems. Generally, reverse flow FFs operate with lower gas flow per unit area of bag surface (air-to-cloth ratio) than pulse jet systems and, thus, are larger and more costly for a given gas flow-rate or application. Fabric filters can achieve very high (>99.9 percent) PM removal efficiencies. These systems are also very effective in controlling fine particulate matter, which results in good control of metals and organics entrained on fine particulate.

Particulate collection in an ESP occurs in three steps: (1) suspended particles are given an electrical charge; (2) the charged particles migrate to a collecting electrode of opposite polarity; and (3) the collected PM is dislodged from the collecting electrodes and collected in hoppers for disposal.

Charging of the particles is usually caused by ions produced in high voltage corona. The electric fields and the corona necessary for particle charging are provided by converting alternating current to direct current using high voltage transformers and rectifiers. Removal of the collected particulate matter is accomplished mechanically by rapping or vibrating the collecting electrode plates. ESPs have been used in many applications due to their high reliability and efficiency in controlling total PM emissions. Except for very large and carefully designed ESPs, however, they are less efficient than FFs at control of fine particulates and metals.

Dry sorbent injection (DSI) is another method for controlling acid gases. In the DSI process, a dry alkaline material is injected into the flue gas into a dry venturi within the ducting or into the duct ahead of a particulate control device. The alkaline material reacts with and neutralizes acids in the flue gas. Fabric filters are employed downstream of DSI to: 1) control the PM generated by the incinerator, 2) capture the DSI reaction products and unreacted sorbent, and 3) increase sorbent/acid gas contact time, thus enhancing acid gas removal efficiency and sorbent utilization. Fabric filters are commonly used with DSI because they provide high sorbent/acid gas contact. Fabric filters are less sensitive to PM loading changes or combustion upsets than other PM control devices since they operate with nearly constant efficiency. A potential disadvantage of ESPs used in conjunction with DSI is that the sorbent increases the electrical resistivity of the PM being collected. This phenomenon makes the PM more difficult to charge and, therefore, to collect. High resistivity can be compensated for by flue gas conditioning or by increasing the plate area and size of the ESP.

The major factors affecting DSI performance are flue gas temperature, acid gas dew point (temperature at which the acid gases condense), and sorbent-to-acid gas ratio. DSI performance improves as the difference between flue gas and acid dew point temperatures decreases and the sorbent-to-acid gas ratio increases. Acid gas removal efficiency with DSI also depends on sorbent type and the extent of sorbent mixing with the flue gas. Sorbents that have been successfully applied include hydrated lime [$Ca(OH)_2$], sodium hydroxide (NaOH), and sodium bicarbonate ($NaHCO_3$). For hydrated lime, DSI can achieve 80 to 95 percent of HCl removal and 40 to 70 percent removal of SO_2 under proper operating conditions.

The primary advantage of DSI compared to wet scrubbers is the relative simplicity of the sorbent preparation, handling, and injection systems as well as the easier handling and disposal of dry

solid process wastes. The primary disadvantages are its lower sorbent utilization rate and correspondingly higher sorbent and waste disposal rates.

In the spray drying process, lime slurry is injected into the SD through either a rotary atomizer or dual-fluid nozzles. The water in the slurry evaporates to cool the flue gas, and the lime reacts with acid gases to form calcium salts that can be removed by a PM control device. The SD is designed to provide sufficient contact and residence time to produce a dry product before leaving the SD adsorber vessel. The residence time in the adsorber vessel is typically 10 to 15 seconds. The particulates leaving the SD (fly ash, calcium salts, and unreacted hydrated lime) are collected by a FF or ESP.

Emission factors and emission factor ratings for controlled air incinerators are presented in Tables 2.6-1 through 2.6-15. For emissions controlled with wet scrubbers, emission factors are presented separately for low, medium, and high energy wet scrubbers. Particle size distribution data for controlled air incinerators are presented in Table 2.6-15 for uncontrolled emissions and controlled emissions following a medium-energy wet scrubber/FF and a low-energy wet scrubber. Emission factors and emission factor ratings for rotary kiln incinerators are presented in Tables 2.6-16 through 2.6-18. Emissions data are not available for pathogens because there is not an accepted methodology for measurement of these emissions. Refer to References 8, 9, 11, 12, and 19 for more information.

Table 2.6-1 (Metric and English Units). EMISSION FACTORS FOR NITROGEN OXIDES (NO_x), CARBON MONOXIDE (CO), AND SULFUR DIOXIDE (SO_2) FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a]
(SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Control Level[b]	NO_x			CO			SO_2		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Uncontrolled	4.95E+00	2.48E+00	B	3.86E+00	1.93E+00	B	2.17E+00	1.09E+00	B
Low Energy Scrubber/FF									
Medium Energy Scrubber/FF							3.75E-01	1.88E-01	E
FF	3.55E+00	1.77E+00	E	1.20E+00	6.01E-01	E	8.45E-01	4.22E-01	E
Low Energy Scrubber	2.12E+00	1.06E+00	E	8.27E-01	4.14E-01	E	2.09E+00	1.04E+00	E
High Energy Scrubber	2.12E+00	1.06E+00	E	8.27E-01	4.14E-01	E	2.57E-02	1.29E-02	E
DSI/FF	6.36E+00	3.18E+00	E	5.32E-01	2.66E-01	E	3.83E-01	1.92E-01	E
DSI/Carbon Injection/FF	2.90E+00	1.45E+00	E	5.09E-03	2.54E-03	E	7.14E-01	3.57E-01	E
DSI/FF/Scrubber							1.51E-02	7.57E-03	E
DSI/ESP				7.08E-03	3.54E-03	E			

[a] References 7-43. SCC = Source Classification Code.
[b] FF = Fabric Filter
DSI = Dry Sorbent Injection
ESP = Electrostatic Precipitator

Table 2.6-2 (Metric and Electric Units). EMISSION FACTORS FOR TOTAL PARTICULATE MATTER, LEAD, AND TOTAL ORGANIC COMPOUNDS (TOC) FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a] (SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Control Level[b]	Total Particulate Matter			Lead[c]			TOC		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Uncontrolled	4.67E+00	2.33E+00	B	7.28E-02	3.64E-02	B	2.99E-01	1.50E-01	B
Low Energy Scrubber/FF	9.09E-01	4.55E-01	E						
Medium Energy Scrubber/FF	1.61E-01	8.03E-02	E	1.60E-03	7.99E-04	E			
FF	1.75E-01	8.76E-02	E	9.92E-05	4.96E-05	E	6.86E-02	3.43E-01	E
Low Energy Scrubber	2.90E+00	1.45E+00	E	7.94E-02	3.97E-02	E	1.40E-01	7.01E-02	E
High Energy Scrubber	1.48E+00	7.41E-01	E	6.98E-02	3.49E-02	E	1.40E-01	7.01E-02	E
DSI/FF	3.37E-01	1.69E-01	E	6.25E-05	3.12E+01	E	4.71E-02	2.35E-02	E
DSI/Carbon Injection/FF	7.23E-02	3.61E-02	E	9.27E-05	4.64E-05	E			
DSI/FF/Scrubber	2.68E+00	1.34E+00	E	5.17E-05	2.58E-05	E			
DSI/ESP	7.34E-01	3.67E-01	E	4.70E-03	2.35E-03	E			

[a] References 7-43. SCC = Source Classification Code.

[b] FF = Fabric Filter
DSI = Dry Sorbent Injection
ESP = Electrostatic Precipitator

[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.6-3 (Metric and English Units). EMISSION FACTORS FOR HYDROGEN CHLORIDE (HCl) AND POLYCHLORINATED BIPHENYLS (PCBs) FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a] (SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Control Level[b]	HCl[c]			Total PCB[c]		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Uncontrolled	3.35E+01	1.68E+01	C	4.65E-05	2.33E-05	E
Low Energy Scrubber/FF	1.90E+00	9.48E-01	E			
Medium Energy Scrubber/FF	2.82E+00	1.41E+00	E			
FF	5.65E+00	2.82E+00	E			
Low Energy Scrubber	1.00E+00	5.01E-01	E			
High Energy Scrubber	1.39E-01	6.97E-02	E			
DSI/FF	1.27E+01	6.37E+00	D			
DSI/Carbon Injection/FF	9.01E-01	4.50E-01	E			
DSI/FF/Scrubber	9.43E-02	4.71E-02	E			
DSI/ESP	4.98E-01	2.49E-01	E			

[a] References 7-43. SCC = Source Classification Code.

[b] FF = Fabric Filter
DSI = Dry Sorbent Injection
ESP = Electrostatic Precipitator

[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.6-4 (Metric and English Units). EMISSION FACTORS FOR ALUMINUM, ANTIMONY, AND ARSENIC CONTROLLED AIR MEDICAL WASTE INCINERATORS[a]
(SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Control Level[b]	Aluminum			Antimony[c]			Arsenic[c]		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Uncontrolled	1.05E-02	5.24E-03	E	1.28E-02	6.39E-03	D	2.42E-04	1.21E-04	B
Low Energy Scrubber/FF									
Medium Energy Scrubber/FF				3.09E-04	1.55E-04	E	3.27E-05	1.53E-02	E
FF							3.95E-08	1.97E-08	E
Low Energy Scrubber							1.42E-04	7.12E-05	E
High Energy Scrubber				4.08E-04	2.04E-04	E	3.27E-05	1.64E-05	E
DSI/FF	3.03E-03	1.51E-03	E	2.10E-04	1.05E-04	E	1.19E-05	5.93E-06	E
DSI/Carbon Injection/FF	2.99E-03	1.50E-03	E	1.51E-04	7.53E-05	E	1.46E-05	7.32E-06	E
DSI/FF/Scrubber									
DSI/ESP							5.01E-05	2.51E-05	E

[a] References 7-43. SCC = Source Classification Code.

[b] FF = Fabric Filter
DSI = Dry Sorbent Injection
ESP = Electrostatic Precipitator

[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.6-5 (Metric and English Units). EMISSION FACTORS FOR BARIUM, BERYLLIUM, AND CADMIUM FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a]
(SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Control Level[b]	Barium			Beryllium[c]			Cadmium[c]		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Uncontrolled	3.24E-03	1.62E-03	D	6.25E-06	3.12E-06	D	5.48E-03	2.74E-03	B
Low Energy Scrubber/FF									
Medium Energy Scrubber/FF	2.07E-04	1.03E-04	E				1.78E-04	8.89E-05	E
FF									
Low Energy Scrubber							6.97E-03	3.49E-03	E
High Energy Scrubber							7.43E-02	3.72E-02	E
DSI/FF	7.39E-05	3.70E-05	E				2.46E-05	1.23E-05	E
DSI/Carbon Injection/FF	7.39E-05	3.69E-05	E	3.84E-06	1.92E-06	E	9.99E-05	4.99E-05	E
DSI/FF/Scrubber							1.30E-05	6.48E-06	E
DSI/ESP							5.93E-04	2.97E-04	E

[a] References 7-43. SCC = Source Classification Code.
[b] FF = Fabric Filter
DSI = Dry Sorbent Injection
ESP = Electrostatic Precipitator
[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.6-6 (Metric and English Units). EMISSION FACTORS FOR CHROMIUM, COPPER, AND IRON FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a]
(SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Control Level[b]	Chromium[c]			Copper			Iron		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Uncontrolled	7.75E-04	3.88E-04	B	1.25E-02	6.24E-03	E	1.44E-02	7.22E-03	C
Low Energy Scrubber/FF									
Medium Energy Scrubber/FF	2.58E-04	1.29E-04	E						
FF	2.15E-06	1.07E-06	E						
Low Energy Scrubber	4.13E-04	2.07E-04	E				9.47E-03	4.73E-03	E
High Energy Scrubber	1.03E-03	5.15E-04	E						
DSI/FF	3.06E-04	1.53E-04	E	1.25E-03	6.25E-04	E			
DSI/Carbon Injection/FF	1.92E-04	9.58E-05	E	2.75E-04	1.37E-04	E			
DSI/FF/Scrubber	3.96E-05	1.98E-05	E						
DSI/ESP	6.58E-04	3.29E-04	E						

[a] References 7-43. SCC = Source Classification Code.
[b] FF = Fabric Filter
DSI = Dry Sorbent Injection
ESP = Electrostatic Precipitator
[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.6-7 (Metric and English Units). EMISSION FACTORS FOR MANGANESE, MERCURY, AND NICKEL FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a]
(SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Control Level[b]	Manganese[c]			Mercury[c]			Nickel[c]		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Uncontrolled	5.67E-04	2.84E-04	C	1.07E-01	5.37E-02	C	5.90E-04	2.95E-04	B
Low Energy Scrubber/FF									
Medium Energy Scrubber/FF				3.07E-02	1.53E-02	E	5.30E-04	2.65E-04	E
FF									
Low Energy Scrubber	4.66E-04	2.33E-04	E	1.55E-02	7.75E-03	E	3.28E-04	1.64E-02	E
High Energy Scrubber	6.12E-04	3.06E-04	E	1.73E-02	8.65E-03	E	2.54E-03	1.27E-03	E
DSI/FF				1.11E-01	5.55E-02	E	4.54E-04	2.27E-04	E
DSI/Carbon Injection/FF				9.74E-03	4.87E-03	E	2.84E-04	1.42E-04	E
DSI/FF/Scrubber				3.56E-04	1.78E-04	E			
DSI/ESP				1.81E-02	9.05E-03	E	4.84E-04	2.42E-04	E

[a] References 7-43. SCC = Source Classification Code.

[b] FF = Fabric Filter
DSI = Dry Sorbent Injection
ESP = Electrostatic Precipitator

[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.6-8 (Metric and English Units). EMISSION FACTORS FOR SILVER AND THALLIUM FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a] (SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Control Level[b]	Silver			Thallium		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Uncontrolled	2.26E-04	1.13E-04	D	1.10E-03	5.51E-04	D
Low Energy Scrubber/FF						
Medium Energy Scrubber/FF	1.71E-04	8.57E-05	E			
FF						
Low Energy Scrubber						
High Energy Scrubber	4.33E-04	2.17E-04	E			
DSI/FF	6.65E-05	3.32E-05	E			
DSI/Carbon Injection/FF	7.19E-05	3.59E-05	E			
DSI/FF/Scrubber						
DSI/ESP						

[a] References 7-43. SCC = Source Classification Code.

[b] FF = Fabric Filter
DSI = Dry Sorbent Injection
ESP = Electrostatic Precipitator

Table 2.6-9 (Metric and English Units). EMISSION FACTORS FOR SULFUR TRIOXIDE (SO_3) AND HYDROGEN BROMIDE (HBr) FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a] (SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Control Level[b]	SO_3			HBr		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Uncontrolled				4.33E-02	2.16E-02	D
Low Energy Scrubber/FF						
Medium Energy Scrubber/FF				5.24E-02	2.62E-02	E
FF						
Low Energy Scrubber						
High Energy Scrubber						
DSI/FF						
DSI/Carbon Injection/FF				4.42E-03	2.21E-03	E
DSI/FF/Scrubber	9.07E-03	4.53E-03	E			
DSI/ESP						

[a] References 7-43. SCC = Source Classification Code.

[b] FF = Fabric Filter
DSI = Dry Sorbent Injection
ESP = Electrostatic Precipitator

Table 2.6-10 (Metric and English Units). EMISSION FACTORS FOR HYDROGEN FLUORIDE AND CHLORINE FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a]
(SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Control Level[b]	Hydrogen Fluoride[c]			Chlorine[c]		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
Uncontrolled	1.49E-01	7.43E-02	D	1.05E-01	5.23E-02	E
Low Energy Scrubber/FF						
Medium Energy Scrubber/FF						
FF						
Low Energy Scrubber						
High Energy Scrubber						
DSI/FF						
DSI/Carbon Injection/FF	1.33E-02	6.66E-03	E			
DSI/FF/Scrubber						
DSI/ESP						

[a] References 7-43. SCC = Source Classification Code.

[b] FF = Fabric Filter
DSI = Dry Sorbent Injection
ESP = Electrostatic Precipitator

[c] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.6-11 (Metric and English Units). CHLORINATED DIBENZO-P-DIOXIN EMISSION FACTORS FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a]
(SCC 50100505, 50200505)
Rating (A-E) Follows Each Factor

Congener[b]	Uncontrolled			Fabric Filter			Wet Scrubber			DSI/FF[c]		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
TCDD												
2,3,7,8-	5.47E-08	2.73E-08	E	6.72E-09	3.36E-09	E	1.29E-10	6.45E-11	E	5.61E-10	2.81E-10	E
Total	1.00E-06	5.01E-07	B	1.23E-07	6.17E-08	E	2.67E-08	1.34E-08	E	6.50E-09	3.25E-09	E
PeCDD												
1,2,3,7,8-							6.08E-10	3.04E-10	E			
Total							5.53E-10	2.77E-10	E			
HxCDD												
1,2,3,6,7,8-	3.78E-10	1.89E-10	E				1.84E-09	9.05E-10	E			
1,2,3,7,8,9-	1.21E-09	6.07E-10	E				2.28E-09	1.14E-09	E			
1,2,3,4,7,8-							9.22E-10	4.61E-10	E			
Total							5.77E-10	2.89E-10	E			
HpCDD												
1,2,3,4,6,7,8-	5.23E-09	2.62E-09	E				6.94E-09	3.47E-09	E			
Total							1.98E-09	9.91E-10	E			
OCDD - total	2.21E-08	1.11E-08	E									
Total CDD	2.13E-05	1.07E-05	B	2.68E-06	1.34E-06	E	1.84E-06	9.18E-07	E	3.44E-07	1.72E-07	E

[a] References 7-43. SCC = Source Classification Code.
[b] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.
[c] FF = Fabric Filter
DSI = Dry Sorbent Injection

Table 2.6-12 (Metric and English Units). CHLORINATED DIBENZO-P-DIOXIN EMISSION FACTORS FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a]
(SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Congener[b]	DSI/Carbon Injection/FF[c]			DSI/ESP[d]		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
TCDD 2,3,7,8- Total	8.23E-10	4.11E-10	E	1.73E-10	8.65E-11	E
PeCDD 1,2,3,7,8- Total						
HxCDD 1,2,3,6,7,8- 1,2,3,7,8,9- 1,2,3,4,7,8- Total						
HpCDD 2,3,4,6,7,8- 1,2,3,4,6,7,8 - Total						
OCDD - total						
Total CDD	5.38E-08	2.69E-08	E			

[a] References 7-43. SCC = Source Classification Code.
[b] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.
[c] FF = Fabric Filter
DSI = Dry Sorbent Injection
[d] ESP = Electrostatic Precipitator

Table 2.6-13 (Metric and English Units). CHLORINATED DIBENZOFURAN EMISSION FACTORS FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a] (SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Congener[b]	Uncontrolled			Fabric Filter			Wet Scrubber			DSI/FF[c]		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
TCDF												
2,3,7,8-	2.40E-07	1.20E-07	E	3.85E-08	1.97E-08	E	1.26E-08	6.30E-09	E	4.93E-09	2.47E-09	E
Total	7.21E-06	3.61E-06	B	1.28E-06	6.39E-07	E	4.45E-07	2.22E-07	E	1.39E-07	6.96E-08	E
PeCDF												
1,2,3,7,8-	7.56E-10	3.78E-10	E				1.04E-09	5.22E-10	E			
2,3,4,7,8-	2.07E-09	1.04E-09	E				3.07E-09	1.53E-09	E			
Total							6.18E-09	3.09E-09	E			
HxCDF												
1,2,3,4,7,8-	7.55E-09	3.77E-09	E				8.96E-09	4.48E-09	E			
1,2,3,6,7,8-	2.53E-09	1.26E-09	E				3.53E-09	1.76E-09	E			
2,3,4,6,7,8-	7.18E-09	3.59E-09	E				9.59E-09	4.80E-09	E			
1,2,3,7,8,9-							3.51E-10	1.76E-10	E			
Total							5.10E-09	2.55E-09	E			
HpCDF												
1,2,3,4,6,7,8 -	1.76E-08	8.78E-09	E				1.79E-08	8.97E-09	E			
1,2,3,4,7,8,9 -	2.72E-09	1.36E-09	E				3.50E-09	1.75E-09	E			
Total							1.91E-09	9.56E-10	E			
OCDF - total	7.42E-08	3.71E-08	E				4.91E-10	2.45E-10	E			
Total CDF	7.15E-05	3.58E-05	B	8.50E-06	4.25E-06	E	4.92E-06	2.46E-06	E	1.47E-06	7.37E-07	E

[a] References 7-43. SCC = Source Classification Code.

[b] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

[c] FF = Fabric Filter
DSI = Dry Sorbent Injection

Table 2.6-14 (Metric and English Units). CHLORINATED DIBENZOFURANS EMISSION FACTORS FOR CONTROLLED AIR MEDICAL WASTE INCINERATORS[a]
(SCC 50100505, 50200505)

Rating (A-E) Follows Each Factor

Congener[b]	DSI/Carbon Injection/FF[c]			DSI/ESP[d]		
	lb/ton	kg/Mg	Rating	lb/ton	kg/Mg	Rating
TCDF						
2,3,7,8-	7.31E-10	3.65E-10	E	1.73E-09	8.66E-10	E
Total	1.01E-08	5.07E-09	E			
PeCDF						
1,2,3,7,8-						
2,3,4,7,8-						
Total						
HxCDF						
1,2,3,4,7,8-						
1,2,3,6,7,8-						
2,3,4,6,7,8-						
1,2,3,7,8,9-						
Total						
HpCDF						
1,2,3,4,6,7,8 -						
1,2,3,4,7,8,9 -						
Total						
OCDF - total						
Total CDF	9.47E-08	4.74E-08	E			

[a] References 7-43. SCC = Source Classification Code.
[b] Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.
[c] FF = Fabric Filter
DSI = Dry Sorbent Injection
[d] ESP = Electrostatic Precipitator

Table 2.6-15. PARTICLE SIZE DISTRIBUTION FOR CONTROLLED AIR MEDICAL WASTE INCINERATOR PARTICULATE MATTER EMISSIONS[a]
(SCC 50100505, 50200505)

EMISSION FACTOR RATING = E

Cut Diameter (microns)	Uncontrolled Cumulative Mass % less than Stated Size	Scrubber Cumulative Mass % less than Stated Size
0.625	31.1	0.1
1.0	35.4	0.2
2.5	43.3	2.7
5.0	52.0	28.1
10.0	65.0	71.9

[a] References 7-43. SCC = Source Classification Code.

Table 2.6-16 (Metric and English Units). ROTARY KILN MEDICAL WASTE INCINERATOR EMISSION FACTORS FOR CRITERIA POLLUTANTS AND ACID GASES[a]
(SCC 50100505, 50200505)

EMISSION FACTOR RATING = E

Pollutant	Uncontrolled		SD/Fabric Filter[b]		SD/Carbon Injection/FF[c]		High Energy Scrubber	
	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg
Carbon monoxide	3.82E-01	1.91E-01	3.89E-02	1.94E-02	4.99E-02	2.50E-02	5.99E-02	3.00E-02
Nitrogen oxides	4.63E+00	2.31E+00	5.25E+00	2.63E+00	4.91E+00	2.45E+00	4.08E+00	2.04E+00
Sulfur dioxide	1.09E+00	5.43E-01	6.47E-01	3.24E-01	3.00E-01	1.50E-01		
PM	3.45E+01	1.73E+01	3.09E-01	1.54E-01	7.56E-02	3.78E-02	8.53E-01	4.27E-01
TOC	6.66E-02	3.33E-02	4.11E-02	2.05E-02	5.05E-02	2.53E-02	2.17E-02	1.08E-02
HCl	4.42E+01	2.21E+01	2.68E-01	1.34E-01	3.57E-01	1.79E-01	2.94E+01	1.47E+01
HF	9.31E-02	4.65E-02	2.99E-02	1.50E-02				
HBr	1.05E+00	5.25E-01	6.01E-02	3.00E-02	1.90E-02	9.48E-03		
H_2SO_4							2.98E+00	1.49E+00

[a] References 7-43. SCC = Source Classification Code.
[b] SD = Spray Dryer
[c] FF = Fabric Filter

Table 2.6-17 (Metric and English Units). ROTARY KILN MEDICAL WASTE INCINERATOR EMISSION FACTORS FOR METALS[a]
(SCC 50100505, 50200505)

EMISSION FACTOR RATING = E

Pollutant	Uncontrolled		SD/Fabric Filter[b]		SD/Carbon Injection/FF[c]	
	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg
Aluminum	6.13E-01	3.06E-01	4.18E-03	2.09E-03	2.62E-03	1.31E-03
Antimony	1.99E-02	9.96E-03	2.13E-04	1.15E-04	1.41E-04	7.04E-05
Arsenic	3.32E-04	1.66E-04				
Barium	8.93E-02	4.46E-02	2.71E-04	1.35E-04	1.25E-04	6.25E-05
Beryllium	4.81E-05	2.41E-05	5.81E-06	2.91E-06		
Cadmium	1.51E-02	7.53E-03	5.36E-05	2.68E-05	2.42E-05	1.21E-05
Chromium	4.43E-03	2.21E-03	9.85E-05	4.92E-05	7.73E-05	3.86E-05
Copper	1.95E-01	9.77E-02	6.23E-04	3.12E-04	4.11E-04	2.06E-04
Lead	1.24E-01	6.19E-02	1.89E-04	9.47E-05	7.38E-05	3.69E-05
Mercury	8.68E-02	4.34E-02	6.65E-02	3.33E-02	7.86E-03	3.93E-03
Nickel	3.53E-03	1.77E-03	8.69E-05	4.34E-05	3.58E-05	1.79E-05
Silver	1.30E-04	6.51E-05	9.23E-05	4.61E-05	8.05E-05	4.03E-05
Thallium	7.58E-04	3.79E-04				

[a] References 7-43. SCC = Source Classification Code.
[b] SD = Spray Dryer
[c] FF = Fabric Filter

Table 2.6-18 (Metric and English Units). ROTARY KILN MEDICAL WASTE INCINERATOR EMISSION FACTORS FOR DIOXINS AND FURANS[a]
(SCC 50100505, 50200505)

EMISSION FACTOR RATING = E

Congener	Uncontrolled		SD/Fabric Filter[b]		SD/Carbon Injection/FF[c]	
	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg
2,3,7,8-TCDD	6.61E-10	3.30E-10	4.52E-10	2.26E-10	6.42E-11	3.21E-11
Total TCDD	7.23E-09	3.61E-09	4.16E-09	2.08E-09	1.55E-10	7.77E-11
Total CDD	7.49E-07	3.75E-07	5.79E-08	2.90E-08	2.01E-08	1.01E-08
2,3,7,8-TCDF	1.67E-08	8.37E-09	1.68E-08	8.42E-09	4.96E-10	2.48E-10
Total TCDF	2.55E-07	1.27E-07	1.92E-07	9.58E-08	1.15E-08	5.74E-09
Total CDF	5.20E-06	2.60E-06	7.91E-07	3.96E-07	7.57E-08	3.78E-08

[a] References 7-43. SCC = Source Classification Code.
[b] SD = Spray Dryer
[c] FF = Fabric Filter

References for Section 2.6

1. *Locating and Estimating Air Toxic Emissions from Medical Waste Incinerators*, U. S. Environmental Protection Agency, Rochester, New York, September 1991.

2. *Hospital Waste Combustion Study: Data Gathering Phase*, EPA-450/3-88-017, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, December 1988.

3. C.R. Brunner, "Biomedical Waste Incineration", presented at the 80th Annual Meeting of the Air Pollution Control Association, New York, New York, June 21-26, 1987. p.10.

4. *Flue Gas Cleaning Technologies for Medical Waste Combustors, Final Report*, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, June 1990.

5. *Municipal Waste Combustion Study; Recycling of Solid Waste*, U. S. Environmental Protection Agency, EPA Contract 68-02-433, pp.5-6.

6. S. Black and J. Netherton, *Disinfection, Sterilization, and Preservation. Second Edition*, 1977, p.729.

7. J. McCormack, *et al.*, *Evaluation Test on a Small Hospital Refuse Incinerator at Saint Bernardine's Hospital in San Bernardino, California*, California Air Resources Board, July 1989.

8. *Medical Waste Incineration Emission Test Report, Cape Fear Memorial Hospital, Wilmington, North Carolina*, U. S. Environmental Protection Agency, December 1991.

9. *Medical Waste Incineration Emission Test Report, Jordan Hospital, Plymouth, Massachusetts*, U. S. Environmental Protection Agency, February 1992.

10. J.E. McCormack, *Evaluation Test of the Kaiser Permanente Hospital Waste Incinerator in San Diego*, California Air Resources Board, March 1990.

11. *Medical Waste Incineration Emission Test Report, Lenoir Memorial Hospital, Kinston, North Carolina*, U. S. Environmental Protection Agency, August 12, 1991.

12. *Medical Waste Incineration Emission Test Report, AMI Central Carolina Hospital, Sanford, North Carolina*, U. S. Environmental Protection Agency, December 1991.

13. A. Jenkins, *Evaluation Test on a Hospital Refuse Incinerator at Cedars Sinai Medical Center, Los Angeles, California*, California Air Resources Board, April 1987.

14. A. Jenkins, *Evaluation Test on a Hospital Refuse Incinerator at Saint Agnes Medical Center, Fresno, California*, California Air Resources Board, April 1987.

15. A. Jenkins, *et al.*, *Evaluation Retest on a Hospital Refuse Incinerator at Sutter General Hospital, Sacramento, California*, California Air Resources Board, April 1988.

16. *Test Report for Swedish American Hospital Consumat Incinerator*, Beling Consultants, Rockford, Illinois, December 1986.

17. J.E. McCormack, *ARB Evaluation Test Conducted on a Hospital Waste Incinerator at Los Angeles County--USC Medical Center, Los Angeles, California*, California Air Resources Board, January 1990.

18. M.J. Bumbaco, *Report on a Stack Sampling Program to Measure the Emissions of Selected Trace Organic Compounds, Particulates, Heavy Metals, and HCl from the Royal Jubilee Hospital Incinerator, Victoria, British Columbia*, Environmental Protection Programs Directorate, April 1983.

19. *Medical Waste Incineration Emission Test Report, Borgess Medical Center, Kalamazoo, Michigan*, EMB Report 91-MWI-9, U. S. Environmental Protection Agency, Office of Air Quality Planning and Standards, December 1991.

20. *Medical Waste Incineration Emission Test Report, Morristown Memorial Hospital, Morristown, New Jersey*, EMB Report 91-MWI-8, U. S. Environmental Protection Agency, Office of Air Quality Planning and Standards, December 1991.

21. *Report of Emission Tests, Burlington County Memorial Hospital, Mount Holly, New Jersey*, New Jersey State Department of Environmental Protection, November 28, 1989.

22. *Results of the November 4 and 11, 1988 Particulate and Chloride Emission Compliance Test on the Morse Boulger Incinerator at the Mayo Foundation Institute Hills Research Facility Located in Rochester, Minnesota*, HDR Techserv, Inc., November 39, 1988.

23. *Source Emission Tests at ERA Tech, North Jackson, Ohio*, Custom Stack Analysis Engineering Report, CSA Company, December 28, 1988.

24. Memo to Data File, Hershey Medical Center, Derry Township, Pennsylvania, from Thomas P. Bianca, Environmental Resources, Commonwealth of Pennsylvania, May 9, 1990.

25. *Stack Emission Testing, Erlanger Medical Center, Chattanooga, Tennessee*, Report I-6299-2, Campbell & Associates, May 6, 1988.

26. *Emission Compliance Test Program, Nazareth Hospital, Philadelphia, Pennsylvania*, Ralph Manco, Nazareth Hospital, September 1989.

27. *Report of Emission Tests, Hamilton Hospital, Hamilton, New Jersey*, New Jersey State Department of Environmental Protection, December 19, 1989.

28. *Report of Emission Tests, Raritan Bay Health Services Corporation, Perth Amboy, New Jersey*, New Jersey State Department of Environmental Protection, December 13, 1989.

29. K.A. Hansen, *Source Emission Evaluation on a Rotary Atomizing Scrubber at Klamath Falls, Oregon*, AM Test, Inc., July 19, 1989.

30. A.A. Wilder, *Final Report for Air Emission Measurements from a Hospital Waste Incinerator*, Safeway Disposal Systems, Inc., Middletown, Connecticut.

31. *Stack Emission Testing, Erlanger Medical Center, Chattanooga, Tennessee*, Report I-6299, Campbell & Associates, April 13, 1988.

32. *Compliance Emission Testing for Memorial Hospital, Chattanooga, Tennessee*, Air Systems Testing, Inc., July 29, 1988.

33. *Source Emission Tests at ERA Tech, Northwood, Ohio*, Custom Stack Analysis Engineering Report, CSA Company, July 27, 1989.

34. *Compliance Testing for Southland Exchange Joint Venture, Hampton, South Carolina*, ETS, Inc., July 1989.

35. *Source Test Report, MEGA of Kentucky*, Louisville, Kentucky, August, 1988.

36. *Report on Particulate and HCL Emission Tests on Therm-Tec Incinerator Stack, Elyra, Ohio*, Maurice L. Kelsey & Associates, Inc., January 24, 1989.

37. *Compliance Emission Testing for Particulate and Hydrogen Chloride at Bio-Medical Service Corporation, Lake City, Georgia*, Air Techniques Inc., May 8, 1989.

38. *Particulate and Chloride Emission Compliance Test on the Environmental Control Incinerator at the Mayo Foundation Institute Hills Research Facility, Rochester, Minnesota*, HDR Techserv, Inc., November 30, 1988.

39. *Report on Particulate and HCL Emission Tests on Therm-Tec Incinerator Stack, Cincinnati, Ohio*, Maurice L. Kelsey & Associates, Inc., May 22, 1989.

40. *Report on Compliance Testing, Hamot Medical Center, Erie, Pennsylvania*, Hamot Medical Center, July 19, 1990.

41. *Compliance Emission Testing for HCA North Park Hospital, Hixson, Tennessee*, Air Systems Testing, Inc., February 16, 1988.

42. *Compliance Particulate Emission Testing on the Pathological Waste Incinerator, Humana Hospital-East Ridge, Chattanooga, Tennessee*, Air Techniques, Inc., November 12, 1987.

43. *Report of Emission Tests, Helene Fuld Medical Center, Trenton, New Jersey*, New Jersey State Department of Environmental Protection, December 1, 1989.

2.7 MUNICIPAL SOLID WASTE LANDFILLS

2.7.1 General[1-4]

A municipal solid waste (MSW) landfill unit is a discrete area of land or an excavation that receives household waste, and that is not a land application unit, surface impoundment, injection well, or waste pile. An MSW landfill unit may also receive other types of wastes, such as commercial solid waste, nonhazardous sludge, and industrial solid waste. The municipal solid waste types potentially accepted by MSW landfills include:

- MSW,
- Household hazardous waste,
- Municipal sludge,
- Municipal waste combustion ash,
- Infectious waste,
- Waste tires,
- Industrial non-hazardous waste,
- Conditionally exempt small quantity generator (CESQG) hazardous waste,
- Construction and demolition waste,
- Agricultural wastes,
- Oil and gas wastes, and
- Mining wastes.

Municipal solid waste management in the United States is dominated by disposal in landfills. Approximately 67 percent of solid waste is landfilled, 16 percent is incinerated, and 17 percent is recycled or composted. There were an estimated 5,345 active MSW landfills in the United States in 1992. In 1990, active landfills were receiving an estimated 118 million megagrams (Mg) (130 million tons) of waste annually, with 55 to 60 percent reported as household waste, and 35 to 45 percent reported as commercial waste.

2.7.2 Process Description[2,5]

There are three major designs for municipal landfills. These are the area, trench, and ramp methods. All of these methods utilize a three step process, which includes spreading the waste, compacting the waste, and covering the waste with soil. The trench and ramp methods are not commonly used, and are not the preferred methods when liners and leachate collection systems are utilized or required by law. The area fill method involves placing waste on the ground surface or landfill liner, spreading it in layers, and compacting with heavy equipment. A daily soil cover is spread over the compacted waste. The trench method entails excavating trenches designed to receive a day's worth of waste. The soil from the excavation is often used for cover material and wind breaks. The ramp method is typically employed on sloping land, where waste is spread and compacted similar to the area method, however, the cover material obtained is generally from the front of the working face of the filling operation.

Modern landfill design often incorporates liners constructed of soil (e.g., recompacted clay), or synthetics (e.g., high density polyethylene), or both to provide an impermeable barrier to leachate (i.e., water that has passed through the landfill) and gas migration from the landfill.

2.7.3 Control Technology[1,2,6]

The Resource Conservation and Recovery Act (RCRA) Subtitle D regulations promulgated on October 9, 1991 require that the concentration of methane generated by MSW landfills not exceed 25 percent of the lower explosive limit (LEL) in on-site structures, such as scale houses, or the LEL at the facility property boundary.

Proposed New Source Performance Standards (NSPS) and emission guidelines for air emissions from MSW landfills for certain new and existing landfills were published in the Federal Register on May 30, 1991. The regulation, if adopted, will require that Best Demonstrated Technology (BDT) be used to reduce MSW landfill emissions from affected new and existing MSW landfills emitting greater than or equal to 150 Mg/yr (165 tons/yr) of non-methanogenic organic compounds (NMOCs). The MSW landfills that would be affected by the proposed NSPS would be each new MSW landfill, and each existing MSW landfill that has accepted waste since November 8, 1987, or that has capacity available for future use. Control systems would require: (1) a well-designed and well-operated gas collection system, and (2) a control device capable of reducing NMOCs in the collected gas by 98 weight-percent.

Landfill gas collection systems are either active or passive systems. Active collection systems provide a pressure gradient in order to extract landfill by use of mechanical blowers or compressors. Passive systems allow the natural pressure gradient created by the increase in landfill pressure from landfill gas generation to mobilize the gas for collection.

Landfill gas control and treatment options include (1) combustion of the landfill gas, and (2) purification of the landfill gas. Combustion techniques include techniques that do not recover energy (i.e., flares and thermal incinerators), and techniques that recover energy (i.e., gas turbines and internal combustion engines) and generate electricity from the combustion of the landfill gas. Boilers can also be employed to recover energy from landfill gas in the form of steam. Flares involve an open combustion process that requires oxygen for combustion, and can be open or enclosed. Thermal incinerators heat an organic chemical to a high enough temperature in the presence of sufficient oxygen to oxidize the chemical to carbon dioxide (CO_2) and water. Purification techniques can also be used to process raw landfill gas to pipeline quality natural gas by using adsorption, absorption, and membranes.

2.7.4 Emissions[2,7]

Methane (CH_4) and CO_2 are the primary constituents of landfill gas, and are produced by microorganisms within the landfill under anaerobic conditions. Transformations of CH_4 and CO_2 are mediated by microbial populations that are adapted to the cycling of materials in anaerobic environments. Landfill gas generation, including rate and composition, proceeds through four phases. The first phase is aerobic [e.g., with oxygen (O_2) available] and the primary gas produced is CO_2. The second phase is characterized by O_2 depletion, resulting in an anaerobic environment, where large amounts of CO_2 and some hydrogen (H_2) are produced. In the third phase, CH_4 production begins, with an accompanying reduction in the amount of CO_2 produced. Nitrogen (N_2) content is initially high in landfill gas in the first phase, and declines sharply as the landfill proceeds through the second and third phases. In the fourth phase, gas production of CH_4, CO_2, and N_2 becomes fairly steady. The total time and phase duration of gas generation varies with landfill conditions (e.g., waste composition, design management, and anaerobic state).

The rate of emissions from a landfill is governed by gas production and transport mechanisms. Production mechanisms involve the production of the emission constituent in its vapor phase through vaporization, biological decomposition, or chemical reaction. Transport mechanisms involve the transportation of a volatile constituent in its vapor phase to the surface of the landfill, through the air boundary layer above the landfill, and into the atmosphere. The three major transport mechanisms that enable transport of a volatile constituent in its vapor phase are diffusion, convection, and displacement.

2.7.4.1 Uncontrolled Emissions — To estimate uncontrolled emissions of the various compounds present in landfill gas, total landfill gas emissions must first be estimated. Uncontrolled CH_4 emissions may be estimated for individual landfills by using a theoretical first-order kinetic model of methane production developed by the EPA.[2] This model is known as the Landfill Air Emissions Estimation model, and can be accessed from the EPA's Control Technology Center bulletin board. The Landfill Air Emissions Estimation model equation is as follows:

$$Q_{CH_4} = L_o \ R \ (e^{-kc} - e^{-kt})$$

where:

Q_{CH_4} = Methane generation rate at time t, m^3/yr;
L_o = Methane generation potential, m^3 CH_4/Mg refuse;
R = Average annual refuse acceptance rate during active life, Mg/yr;
e = Base log, unitless;
k = Methane generation rate constant, yr^{-1};
c = Time since landfill closure, yrs (c = 0 for active landfills); and
t = Time since the initial refuse placement, yrs.

Site-specific landfill information is generally available for variables R, c, and t. When refuse acceptance rate information is scant or unknown, R can be determined by dividing the refuse in place by the age of the landfill. Also, nondegradable refuse should be subtracted from the mass of acceptance rate to prevent overestimation of CH_4 generation. The average annual acceptance rate should only be estimated by this method when there is inadequate information available on the actual average acceptance rate.

Values for variables L_o and k must be estimated. Estimation of the potential CH_4 generation capacity of refuse (L_o) is generally treated as a function of the moisture and organic content of the refuse. Estimation of the CH_4 generation constant (k) is a function of a variety of factors, including moisture, pH, temperature, and other environmental factors, and landfill operating conditions. Specific CH_4 generation constants can be computed by use of the EPA Method 2E.

The Landfill Air Emission Estimation model uses the proposed regulatory default values for L_o and k. However, the defaults were developed for regulatory compliance purposes. As a result, it contains conservative L_o and k default values in order to protect human health, to encompass a wide range of landfills, and to encourage the use of site-specific data. Therefore, different L_o and k values may be appropriate in estimating landfill emissions for particular landfills and for use in an emissions inventory.

A k value of 0.04/yr is appropriate for areas with normal or above normal precipitation rather than the default value of 0.02/yr. For landfills with drier waste, a k value of 0.02/yr is more appropriate. An L_o value of 125 m^3/Mg (4,411 ft^3/Mg) refuse is appropriate for most landfills. It should be emphasized that in order to comply with the NSPS, the model defaults for k and L_o must be applied as specified in the final rule.

Landfill gas consists of approximately 50 percent by volume CO_2, 50 percent CH_4, and trace amounts of NMOCs when gas generation reaches steady state conditions. Therefore, the estimate derived for CH_4 generation using the Landfill Air Emissions Estimation model can also be used to represent CO_2 generation. Addition of the CH_4 and CO_2 emissions will yield an estimate of total landfill gas emissions. If site specific information is available to suggest that the CH_4 content of landfill gas is not 50 percent, then the site specific information should be used, and the CO_2 emission estimate should be adjusted accordingly.

Emissions of NMOCs result from NMOCs contained in the landfilled waste, and from their creation from biological processes and chemical reactions within the landfill cell. The Landfill Air Emissions Estimation model contains a proposed regulatory default value for total NMOCs of 8000 ppmv, expressed as hexane. However, there is a wide range for total NMOC values from landfills. The proposed regulatory default value for NMOC concentration was developed for regulatory compliance and to provide the most cost-effective default values on a national basis. For emissions inventory purposes, it would be preferable that site-specific information be taken into account when determining the total NMOC concentration. A value of 4,400 ppmv as hexane is preferable for landfills known to have co-disposal of MSW and commercial/industrial organic wastes. If the landfill is known to contain only MSW or have very little organic commercial/industrial wastes, then a total NMOC value of 1,170 ppmv as hexane should be used.

If a site-specific total NMOC concentration is available (i.e., as measured by EPA Reference Method 25C), it must be corrected for air infiltration into the collected landfill gas before it can be combined with the estimated landfill gas emissions to estimate total NMOC emissions. The total NMOC concentration is adjusted for air infiltration by assuming that CO_2 and CH_4 are the primary (100 percent) constituents of landfill gas, and the following equation is used:

$$\frac{C_{NMOC}\ (\text{ppmv as hexane})\ (1 \times 10^6)}{C_{CO_2}\ (\text{ppmv}) + C_{CH_4}\ (\text{ppmv})} = C_{NMOC}\ \text{ppmv as hexane (corrected for air infiltration)}$$

where:

C_{NMOC} = Total NMOC concentration in landfill gas, ppmv as hexane;
C_{CO_2} = CO_2 concentration in landfill gas, ppmv;
C_{CH} = CH_4 Concentration in landfill gas, ppmv; and
1×10^6 = Constant used to correct NMOC concentration to units of ppmv.

Values for C_{CO_2} and C_{CH_4} can be usually be found in the source test report for the particular landfill along with the total NMOC concentration data.

To estimate total NMOC emissions, the following equation should be used:

$$Q_{NMOC} = 2\ Q_{CH_4} * C_{NMOC}/(1 \times 10^6)$$

where:

Q_{NMOC} = NMOC emission rate, m^3/yr;
Q_{CH_4} = CH_4 generation rate, m^3/yr (from the Landfill Air Emissions Estimation model);
C_{NMOC} = Total NMOC concentration in landfill gas, ppmv as hexane; and
2 = Multiplication factor (assumes that approximately 50 percent of landfill gas is CH_4).

The mass emissions per year of total NMOCs (as hexane) can be estimated by the following equation:

$$M_{NMOC} = Q_{NMOC} * \left[\frac{1050.2}{(273+T)}\right]$$

where:

M_{NMOC} = NMOC (total) mass emissions (Mg/yr);
Q_{NMOC} = NMOC emission rate (m^3/yr); and
T = Temperature of landfill gas (^oC).

This equation assumes that the operating pressure of the system is approximately 1 atmosphere, and represents total NMOC based on the molecular weight of hexane. If the temperature of the landfill gas is not known, a temperature of 25°C (75°F) is recommended.

Uncontrolled emission concentrations of individual NMOCs along with some inorganic compounds are presented in Table 2.7-1. These individual NMOC and inorganic concentrations have already been corrected for air infiltration and can be used as input parameters in the Landfill Air Emission Estimation model for estimating individual NMOC emissions from landfills when site-specific data are not available. An analysis of the data based on the co-disposal history (with hazardous wastes) of the individual landfills from which the concentration data were derived indicates that for benzene and toluene, there is a difference in the uncontrolled concentration. Table 2.7-2 presents the corrected concentrations for benzene and toluene to use based on the site's co-disposal history.

Similar to the estimation of total NMOC emissions, individual NMOC emissions can be estimated by the following equation:

$$Q_{NMOC} = 2\ Q_{CH_4} *\ C_{NMOC}/(1 \times 10^6)$$

where:

Q_{NMOC} = NMOC emission rate, m^3/yr;
Q_{CH_4} = CH_4 generation rate, m^3/yr (from the Landfill Air Emission Estimation model);
C_{NMOC} = NMOC concentration in landfill gas, ppmv; and
2 = Multiplication factor (assumes that approximately 50 percent of landfill gas is CH_4).

Table 2.7-1. UNCONTROLLED LANDFILL GAS CONCENTRATIONS[a]

(SCC 50200602)

Compound	Median ppmv	Emission Factor Rating
1,1,1-Trichloroethane (methyl chloroform)*	0.27	B
1,1,2,2-Tetrachloroethane*	0.20	C
1,1,2-Trichloroethane*	0.10	E
1,1-Dichloroethane (ethylidene dichloride)*	2.07	B
1,1-Dichloroethene (vinylidene chloride)*	0.22	B
1,2-Dichloroethane (ethylene dichloride)*	0.79	B
1,2-Dichloropropane (propylene dichloride)*	0.17	C
Acetone	8.89	B
Acrylonitrile*	7.56	D
Bromodichloromethane	2.06	C
Butane	3.83	B
Carbon disulfide*	1.00	E
Carbon monoxide	309.32	C
Carbon tetrachloride*	0.00	B
Carbonyl sulfide*	24.00	E
Chlorobenzene*	0.20	D
Chlorodiflouromethane	1.22	B
Chloroethane (ethyl chloride)*	1.17	B
Chloroform*	0.27	B
Chloromethane	1.14	B
Dichlorodifluoromethane	12.17	B
Dichlorofluoromethane	4.37	C
Dichloromethane (methylene chloride)*	14.30	C
Dimethyl sulfide	76.16	B
Ethane	227.65	D
Ethyl mercaptan	0.86	C
Ethylbenzene*	4.49	B
Fluorotrichloromethane	0.73	B
Hexane*	6.64	B
Hydrogen sulfide	36.51	B
Methyl ethyl ketone	6.13	B
Methyl isobutyl ketone*	1.22	B
Methyl mercaptan	10.43	B

Table 2.7-1. (Cont.).

Compound	Median ppmv	Emission Factor Rating
NMOC (as hexane)	1170	D
Pentane	3.32	B
Perchloroethylene (tetrachloroethene)*	3.44	B
Propane	10.60	B
Trichloroethene*	2.08	B
t-1,2-dichloroethene	4.01	B
Vinyl chloride*	7.37	B
Xylene*	12.25	B

[a] References 9-35. SCC = Source Classification Code

* = Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

Table 2.7-2. UNCONTROLLED CONCENTRATIONS OF BENZENE AND TOLUENE BASED ON HAZARDOUS WASTE DISPOSAL HISTORY[a]

(SCC 50200602)

	Concentration ppmv	Emission Factor Rating
Benzene*		
Co-disposal	24.99	D
Unknown	2.25	B
No co-disposal	0.37	D
Toluene*		
Co-disposal	102.62	D
Unknown	31.63	B
No co-disposal	8.93	D

[a] References 9-35. SCC = Source Classification Code.

* = Hazardous Air Pollutants listed in Title I of the 1990 Clean Air Act Amendments.

The mass emissions per year of each individual landfill gas compound can be estimated by the following equation:

$$I_{NMOC} = Q_{NMOC} * \frac{\text{(Molecular weight of compound)}}{(8.205 \times 10^{-5}\ m^3\text{-atm/mol-}^\circ K)\ (1000\ g)(273 + T)}$$

where:

I_{NMOC} = Individual NMOC mass emissions (Mg/yr);
Q_{NMOC} = NMOC emission rate (m^3/yr); and
T = Temperature of landfill gas (°C).

2.7.4.2 Controlled Emissions — Emissions from landfills are typically controlled by installing a gas collection system, and destroying the collected gas through the use of internal combustion engines, flares, or turbines. Gas collection systems are not 100 percent efficient in collecting landfill gas, so emissions of CH_4 and NMOCs at a landfill with a gas recovery system still occur. To estimate controlled emissions of CH_4, NMOCs, and other constituents in landfill gas, the collection efficiency of the system must first be estimated. Reported collection efficiencies typically range from 60 to 85 percent, with an average of 75 percent most commonly assumed. If site-specific collection efficiencies are available, they should be used instead of the 75 percent average.

Uncollected CH_4, CO_2, and NMOCs can be calculated with the following equation:

$$1 - \frac{\text{Collection Efficiency}}{100}$$

Controlled emission estimates also need to take into account the control efficiency of the control device. Control efficiencies of CH_4 and NMOCs with differing control devices are presented in Table 2.7-3. Emissions from the control devices need to be added to the uncollected emissions to estimate total controlled emissions.

Emission factors for secondary compounds (CO_2, CO, and NO_x) exiting the control device are presented in Tables 2.7-4 and 2.7-5.

The reader is referred to Sections 11.2-1 (Unpaved Roads, SCC 50100401), and 11-2.4 (Heavy Construction Operations) of Volume I, and Section II-7 (Heavy-duty Construction Equipment) of Volume II, of the AP-42 document for determination of associated dust and exhaust emissions from these emission sources at MSW landfills.

Table 2.7-3. CONTROL EFFICIENCIES FOR LANDFILL GAS CONSTITUENTS[a]

Control Device	Compound	Average Control Efficiency	Emission Factor Rating
IC Engine (no SCC)	Benzene	83.83	E
	Trichloroethylene	89.60	E
	Perchloroethylene	89.41	E
	NMOCs (as hexane)	79.75	E
	1,1,1-Trichloroethane	92.47	E
	Chloroform	99.00	E
	Toluene	79.71	E
	Carbon tetrachloride	98.50	E
Turbine (no SCC)	Perchloroethylene	99.97	E
	Toluene	99.91	E
	1,1,1-Trichloroethane	95.18	E
	Trichloroethylene	99.92	E
	Vinyl chloride	98.00	E
Flare (50200601) (50300601)	Chloroform	93.04	D
	Perchloroethylene	85.02	C
	Toluene	93.55	C
	Xylene	99.28	E
	1,1,1-Trichloroethane	85.24	C
	1,2-Dichloroethane	88.68	E
	Benzene	89.50	C
	Carbon tetrachloride	95.05	D
	Methylene chloride	97.60	E
	NMOCs (as hexane)	83.16	E
	Trichloroethylene	96.20	C
	t-1,2-dichloroethene	99.59	E
	Vinyl chloride	97.61	C

[a] References 9-35. Source Classification Codes in parenthesis.

Table 2.7-4. (Metric Units) EMISSION RATES FOR SECONDARY COMPOUNDS EXITING CONTROL DEVICES[a]

Control Device	Compound	Average Rate, kg/hr/dscmm Uncontrolled Methane	Emission Factor Rating
Flare (50200601) (50300601)	Carbon dioxide	135.4	B
	Carbon monoxide	0.80	B
	Nitrogen dioxide	0.11	C
	Methane	1.60	C
	Sulfur dioxide	0.03	E
ICE (no SCC)	Carbon dioxide	182.37	E
	Nitrogen dioxide	0.80	E
Turbine (no SCC)	Carbon dioxide	49.36	E
	Carbon monoxide	0.32	E

[a] Source Classification Codes in parenthesis.

Table 2.7-5. (English Units) EMISSION RATES FOR SECONDARY COMPOUNDS EXITING CONTROL DEVICES[a]

Control Device	Compound	Average Rate, lb/hr/dscfm Uncontrolled Methane	Emission Factor Rating
Flare (50200601) (50300601)	Carbon dioxide	8.450	B
	Carbon monoxide	0.050	B
	Nitrogen dioxide	0.007	C
	Methane	0.105	C
	Sulfur dioxide	0.002	E
IC Engine (no SCC)	Carbon dioxide	11.380	E
	Nitrogen dioxide	0.050	E
Turbine (no SCC)	Carbon dioxide	3.080	D
	Carbon monoxide	0.021	E

[a] Source Classification Codes in parenthesis.

References for Section 2.7

1. *Criteria for Municipal Solid Waste Landfills.* 40 CFR Part 258, Volume 56, No. 196. October 9, 1991.

2. *Air Emissions from Municipal Solid Waste Landfills - Background Information for Proposed Standards and Guidelines.* Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency. Research Triangle Park, North Carolina. EPA-450/3-90-011a. Chapters 3 and 4. March 1991.

3. *Characterization of Municipal Solid Waste in the United States: 1992 Update.* Office of Solid Waste, U. S. Environmental Protection Agency, Washington, D.C. EPA-530-R-92-019. NTIS No. PB92-207-166. July 1992.

4. Eastern Research Group, Inc., *List of Municipal Solid Waste Landfills.* Prepared for the U. S. Environmental Protection Agency, Office of Solid Waste, Municipal and Industrial Solid Waste Division, Washington, D.C. September 1992.

5. *Suggested Control Measures for Landfill Gas Emissions.* State of California Air Resources Board, Stationary Source Division, Sacramento, California. August 1990.

6. *Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills; Proposed Rule, Guideline, and Notice of Public Hearing.* 40 CFR Parts 51, 52, and 60. Vol. 56, No. 104. May 30, 1991.

7. S.W. Zison, Landfill Gas Production Curves. "Myth Versus Reality." Pacific Energy, City of Commerce, California. [Unpublished]

8. R.L. Peer, et al., *Development of an Empirical Model of Methane Emissions from Landfills.* U.S. Environmental Protection Agency, Office of Research and Development. EPA-600/R-92-037. 1992.

9. A.R. Chowdhury, *Emissions from a Landfill Gas-Fired Turbine/Generator Set. Source Test Report C-84-33.* Los Angeles County Sanitation District, South Coast Air Quality Management District, June 28, 1984.

10. Engineering-Science, Inc., *Report of Stack Testing at County Sanitation District Los Angeles Puente Hills Landfill.* Los Angeles County Sanitation District, August 15, 1984.

11. J.R. Manker, *Vinyl Chloride (and Other Organic Compounds) Content of Landfill Gas Vented to an Inoperative Flare, Source Test Report 84-496.* David Price Company, South Coast Air Quality Management District, November 30, 1984.

12. S. Mainoff, *Landfill Gas Composition, Source Test Report 85-102.* Bradley Pit Landfill, South Coast Air Quality Management District, May 22, 1985.

13. J. Littman, *Vinyl Chloride and Other Selected Compounds Present in A Landfill Gas Collection System Prior to and after Flaring, Source Test Report 85-369.* Los Angeles County Sanitation District, South Coast Air Quality Management District, October 9, 1985.

14. W.A. Nakagawa, *Emissions from a Landfill Exhausting Through a Flare System, Source Test Report 85-461.* Operating Industries, South Coast Air Quality Management District, October 14, 1985.

15. S. Marinoff, *Emissions from a Landfill Gas Collection System, Source Test Report 85-511.* Sheldon Street Landfill, South Coast Air Quality Management District, December 9, 1985.

16. W.A. Nakagawa, *Vinyl Chloride and Other Selected Compounds Present in a Landfill Gas Collection System Prior to and after Flaring, Source Test Report 85-592.* Mission Canyon Landfill, Los Angeles County Sanitation District, South Coast Air Quality Management District, January 16, 1986.

17. California Air Resources Board, *Evaluation Test on a Landfill Gas-Fired Flare at the BBK Landfill Facility.* West Covina, California, ARB-SS-87-09, July 1986.

18. S. Marinoff, *Gaseous Composition from a Landfill Gas Collection System and Flare, Source Test Report 86-0342.* Syufy Enterprises, South Coast Air Quality Management District, August 21, 1986.

19. *Analytical Laboratory Report for Source Test.* Azusa Land Reclamation, June 30, 1983, South Coast Air Quality Management District.

20. J.R. Manker, *Source Test Report C-84-202.* Bradley Pit Landfill, South Coast Air Quality Management District, May 25, 1984.

21. S. Marinoff, *Source Test Report 84-315.* Puente Hills Landfill, South Coast Air Quality Management District, February 6, 1985.

22. P.P. Chavez, *Source Test Report 84-596.* Bradley Pit Landfill, South Coast Air Quality Management District, March 11, 1985.

23. S. Marinoff, *Source Test Report 84-373.* Los Angeles By-Products, South Coast air Quality Management District, March 27, 1985.

24. J. Littman, *Source Test Report 85-403.* Palos Verdes Landfill, South Coast Air Quality Management District, September 25, 1985.

25. S. Marinoff, *Source Test Report 86-0234.* Pacific Lighting Energy Systems, South Coast Air Quality Management District, July 16, 1986.

26. South Coast Air Quality Management District, *Evaluation Test on a Landfill Gas-Fired Flare at the Los Angeles County Sanitation District's Puente Hills Landfill Facility.* [ARB/SS-87-06], Sacramento, California, July 1986.

27. D.L. Campbell, et al., *Analysis of Factors Affecting Methane Gas Recovery from Six Landfills*. Air and Energy Engineering Research Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. EPA-600/2-91-055. September 1991.

28. Browning-Ferris Industries, *Source Test Report*. Lyon Development Landfill, August 21, 1990.

29. X.V. Via, *Source Test Report*. Browning-Ferris Industries. Azusa Landfill.

30. M. Nourot, *Gaseous Composition from a Landfill Gas Collection System and Flare Outlet*. Laidlaw Gas Recovery Systems, to J.R. Farmer, OAQPS:ESD, December 8, 1987.

31. D.A. Stringham and W.H. Wolfe, *Waste Management of North America, Inc.*, to J. R. Farmer, OAQPS:ESD, January 29, 1988, Response to Section 114 questionnaire.

32. V. Espinosa, *Source Test Report 87-0318*. Los Angeles County Sanitation District Calabasas Landfill, South Coast Air Quality Management District, December 16, 1987.

33. C.S. Bhatt, *Source Test Report 87-0329*. Los Angeles County Sanitation District, Scholl Canyon Landfill, South Coast Air Quality Management District, December 4, 1987.

34. V. Espinosa, *Source Test Report 87-0391*. Puente Hills Landfill, South Coast Air Quality Management District, February 5, 1988.

35. V. Espinosa, *Source Test Report 87-0376*. Palos Verdes Landfill, South Coast Air Quality Management District, February 9, 1987.

3.1 STATIONARY GAS TURBINES FOR ELECTRICITY GENERATION

3.1.1 General

Stationary gas turbines are applied in electric power generators, in gas pipeline pump and compressor drives, and in various process industries. Gas turbines (greater than 3 MW(e)) are used in electrical generation for continuous, peaking, or standby power. The primary fuels used are natural gas and distillate (No. 2) fuel oil, although residual fuel oil is used in a few applications.

3.1.2 Emissions

Emission control technologies for gas turbines have advanced to a point where all new and most existing units are complying with various levels of specified emission limits. For these sources, the emission factors become an operational specification rather than a parameter to be quantified by testing. This section treats uncontrolled (i.e., baseline) emissions and controlled emissions with specific control technologies.

The emission factors presented are for simple cycle gas turbines. These factors also apply to cogeneration/combined cycle gas turbines. In general, if the heat recovery steam generator (HRSG) is not supplementary fired, the simple cycle input specific emission factors (lb/MMBtu) will apply to cogeneration/combined cycle systems. The output specific emissions (g/hp-hr) will decrease according to the ratio of simple cycle to combined cycle power output. If the HRSG is supplementary fired, the emissions and fuel usage must be considered to estimate stack emissions. Nitrogen Oxide (NO_x) emissions from regenerative cycle turbines (which account for only a small percentage of turbines in use) are greater than emissions from simple cycle turbines because of the increased combustion air temperature entering the turbine. The carbon monoxide (CO) and hydrocarbon (HC) emissions may be lower with the regenerative system for a comparable design. More power is produced from the same energy input, so the input specific emissions factor will be affected by changes in emissions, while output specific emissions will reflect the increased power output.

Water/steam injection is the most prevalent NO_x control for cogeneration/combined cycle gas turbines. The water or steam is injected with the air and fuel into the turbine combustion can in order to lower the peak temperatures which, in turn, decreases the thermal NO_x produced. The lower average temperature within the combustor can may produce higher levels of CO and HC as a result of incomplete combustion.

Selective catalytic reduction (SCR) is a post-combustion control which selectively reduces NO_x by reaction of ammonia and NO on a catalytic surface to form N_2 and H_2O. Although SCR systems can be used alone, all existing applications of SCR have been used in conjunction with water/steam injection controls. For optimum SCR operation, the flue gas must be within a temperature range of 600-800°F with the precise limits dependent on the catalyst. Some SCR systems also utilize a CO catalyst to give simultaneous catalytic CO/NO_x control.

Advanced combustor can designs are currently being phased into production turbines. These dry techniques decrease turbine emissions by modifying the combustion mixing, air staging, and flame stabilization to allow operation at a much leaner air/fuel ratio relative to normal operation. Operating at leaner conditions will lower peak temperatures within the primary flame zone of the combustor. The lower temperatures may also increase CO and HC emissions.

With the proliferation and advancement of NO_x control technologies for gas turbines during the past 15 years, the emission factors for the installed gas turbine population are quite different than uncontrolled turbines. However, uncontrolled turbine emissions have not changed significantly. Therefore a careful review of specific turbine details should be performed before applying uncontrolled emission factors. Today most gas turbines are controlled to meet local, state, and/or federal regulations.

The average gaseous emission factors for uncontrolled gas turbines (firing natural gas and fuel oil) are presented in Tables 3.1-1 and 3.1-2. There is some variation in emissions over the population of large uncontrolled gas turbines because of the diversity of engine designs and models. Tables 3.1-3 and 3.1-4 present emission factors for gas turbines controlled for NO_x using water injection, steam injection or SCR. Tables 3.1-5 and 3.1-6 present emission factors for large distillate oil-fired turbines controlled for NO_x using water injection.

Gas turbines firing distillate or residual oil may emit trace metals carried over from the metals content of the fuel. If the fuel analysis is known, the metals content of the fuel should be used for flue gas emission factors assuming all metals pass through the turbine. If the fuel analysis is not known, Table 3.1-7 provides order of magnitude levels of trace elements for turbines fired with distillate oil.

TABLE 3.1-1. (ENGLISH UNITS)
EMISSION FACTORS FOR LARGE UNCONTROLLED GAS TURBINES[a]
(Source Classification Codes)

Pollutant	Emission Factor Rating[b]	Natural Gas (SCC 20100201)		Fuel Oil (i.e. Distillate) (SCC 20100101)	
		[grams/hr-hp][c] (power output)	[lb/MMBtu] (fuel input)	[grams/hp-hr][c] (power output)	[lb/MMBtu] (fuel input)
NO_x	C	1.6	0.44	2.54	.698
CO	D	.39	.11	.174	.048
CO_2[d]	B	407	112	596	164
TOC (as methane)	D	.087	.024	.062	.017
SO_x (as SO_2)[e]	B	3.41S	.94S	3.67S	1.01S
PM (solids)	E	.070	.0193	.138	.038
PM (condensables)	E	.082	.0226	.084	.023
PM Sizing %					
< .05 microns	D		15%		16%
< .10 microns	D		40%		48%
< .15 microns	D		63%		72%
< .20 microns	D		78%		85%
< .25 microns	D		89%		93%
< 1 micron	D		100%		100%

[a]References 1 - 8.
[b]"D" and "E" rated emission factors are due to limited data and/or a lack of documentation of test results, may not be suitable for specific facilities or populations and should be used with care.
[c]Calculated from lb/MMBtu assuming an average heat rate of 8,000 Btu/hp-hr (x 3.632).
[d]Based on 100 percent conversion of the fuel carbon to CO_2. CO_2 [lb/MMBtu] = 3.67*C/E, where C = carbon content of fuel by weight (0.7), and E = energy content of fuel, (0.0023 MMBtu/lb). The uncontrolled CO_2 emission factors are also applicable to controlled gas turbines.
[e]All sulfur in the fuel is converted to SO_2. S = percent sulfur in fuel.

TABLE 3.1-2. (METRIC UNITS)
EMISSION FACTORS FOR LARGE UNCONTROLLED GAS TURBINES[a]
(Source Classification Codes)

Pollutant	Emission factor Rating[b]	Natural Gas (SCC 20100201)		Fuel Oil (i.e. Distillate) (SCC 20100101)	
		[grams/kW-hr[c] (power output)	[ng/J] (fuel input)	[grams/kW-hr][c] (power output)	[ng/J] (fuel input)
NO_x	C	2.15	190	3.41	300
CO	D	.52	46	.233	20.6
CO_2[d]	B	546	48160	799	70520
TOC (as methane)	D	.117	10.32	.083	7.31
SO_x (as SO_2)[e]	B	4.57S	404S	4.92S	434.3S
PM (solids)	E	.094	8.30	.185	16.3
PM (condensables)	E	.11	9.72	.113	9.89
PM Sizing %					
< .05 microns	D		15%		16%
< .10 microns	D		40%		48%
< .15 microns	D		63%		72%
< .20 microns	D		78%		85%
< .25 microns	D		89%		93%
< 1 micron	D		100%		100%

[a]References 1 - 8.
[b]"D" and "E" rated emission factors are due to limited data and/or a lack of documentation of test results, may not be suitable for specific facilities or populations and should be used with care.
[c]Calculated from ng/J assuming an average heat rate of 11,318 kJ/kW-hr.
[d]Based on 100 percent conversion of the fuel carbon to CO_2. CO_2 [lb/MMBtu] = 3.67*C/E, where C = ratio of carbon in the fuel by weight, and E = energy content of fuel, MMBtu/lb. The uncontrolled CO_2 emission factors are also applicable to controlled gas turbines.
[e]All sulfur in the fuel is assumed to be converted to SO_2.

TABLE 3.1-3. (ENGLISH UNITS)
EMISSION FACTORS FOR LARGE GAS-FIRED CONTROLLED GAS TURBINES[a]
(Source Classification Code: 20100201)

EMISSION FACTOR RATING: C

Pollutant	Water Injection (.8 water/fuel ratio)		Steam Injection (1.2 water/fuel ratio)		Selective Catalytic Reduction (with water injection)
	[grams/hr-hp] (power output)	[lb/MMBtu] (fuel input)	[grams/hr-hp] (power output)	[lb/MMBtu] (fuel input)	[lb/MMBtu] (fuel input)
NO_x	.50	.14	.44	.12	.03[b]
CO	.94	.28	.53	.16	.0084
TOC (as methane)					.014
NH_3					.0065
NMHC					.0032
Formaldehyde					.0027

[a]References 3, 10 - 15. All data are averages of a limited number of tests and may not be typical of those reductions which can be achieved at a specific location.
[b]Average of 78 percent reduction of NO_x through the SCR catalyst.

TABLE 3.1-4. (METRIC UNITS)
EMISSION FACTORS FOR LARGE GAS-FIRED CONTROLLED GAS TURBINES[a]
(Source Classification Code: 20100201)

EMISSION FACTOR RATING: C

Pollutant	Water Injection (0.8 water/fuel ratio)		Steam Injection (1.2 water/fuel ratio)		Selective Catalytic Reduction (with water injection)
	[grams/kW-hr] (power output)	[ng/J] (fuel input)	[grams/kW-hr] (power output)	[ng/J] (fuel input)	[ng/J] (fuel input)
NO_x	.66	61	.59	52	3.78[b]
CO	1.3	120	.71	69	3.61
TOC (as methane)					6.02
NH_3					2.80
NMHC					1.38
Formaldehyde					1.16

[a]References 3, 10 - 15. All data are averages of a limited number of tests and may not be typical of those reductions which can be achieved at a specific location.
[b]Average of 78 percent reduction of NO_x through the SCR catalyst.

TABLE 3.1-5. (ENGLISH UNITS) EMISSION FACTORS FOR LARGE DISTILLATE OIL-FIRED CONTROLLED GAS TURBINES[a]
(Source Classification Code: 20100101)

Pollutant	Emission Factor Rating	Water Injection (.8 water/fuel ratio)	
		[grams/hr-hp][b] (power output)	[lb/MMBtu] (fuel input)
NO_x	E	1.05	.290
CO	E	.067	.0192
TOC (as methane)	E	.017	.0048
SOx	B	[c]	[c]
PM	E	.135	.0372

[a]Reference 16.
[b]Calculated from fuel input assuming an average heat rate of 8,000 Btu/hp-hr (x 3.632).
[c]All sulfur in the fuel is assumed to be converted to SO_x.

TABLE 3.1-6. (METRIC UNITS) EMISSION FACTORS FOR LARGE DISTILLATE OIL-FIRED CONTROLLED GAS TURBINES[a]
(Source Classification Code: 20100101)

Pollutant	Emission Factor Rating	Water Injection (.8 water/fuel ratio)	
		[grams/kW-hr][b] (power output)	[ng/J] (fuel input)
NO_x	E	1.41	125
CO	E	.090	8.26
TOC (as methane)	E	.023	2.06
SO_x	B	[c]	[c]
PM	E	.181	16.00

[a]Reference 16.
[b]Calculated from fuel input assuming an average heat rate of 8,000 Btu/hp-hr (x 3.632).
[c]All sulfur in the fuel is assumed to be converted to SO_x.

TABLE 3.1-7. TRACE ELEMENT EMISSION FACTORS FOR DISTILLATE OIL-FIRED GAS TURBINES[a]
(Source Classification Code: 20100101)

EMISSION FACTOR RATING: E[b]

Trace Element	pg/J	lb/MMBtu
Aluminum	64	1.5 E-04
Antimony	9.4	2.2 E-05
Arsenic	2.1	4.9 E-06
Barium	8.4	2.0 E-05
Beryllium	.14	3.3 E-07
Boron	28	6.5 E-05
Bromine	1.8	4.2 E-06
Cadmium	1.8	4.2 E-06
Calcium	330	7.7 E-04
Chromium	20	4.7 E-05
Cobalt	3.9	9.1 E-06
Copper	578	1.3 E-03
Iron	256	6.0 E-04
Lead	25	5.8 E-05
Magnesium	100	2.3 E-04
Manganese	145	3.4 E-04
Mercury	.39	9.1 E-07
Molybdenum	3.6	8.4 E-06
Nickel	526	1.2 E-03
Phosphorus	127	3.0 E-04
Potassium	185	4.3 E-04
Selenium	2.3	5.3 E-06
Silicon	575	1.3 E-03
Sodium	590	1.4 E-03
Tin	35	8.1 E-05
Vanadium	1.9	4.4 E-06
Zinc	294	6.8 E-04

[a]Reference 1.
[b]Emission factor rating of "E" indicates that the data are from a limited data set and may not be representative of a specific source or population of sources.

REFERENCES FOR SECTION 3.1

1. Shih, C.C., J.W. Hamersma, and D.G. Ackerman, R.G. Beimer, M.L. Kraft, and M.M. Yamada, Emissions Assessment of Conventional Stationary Combustion Systems; Vol. II Internal Combustion Sources, Industrial Environmental Research Laboratory, EPA-600/7-79-029c, U.S. Environmental Protection Agency, Research Triangle Park, NC, February 1979.

2. Final Report - Gas Turbine Emission Measurement Program, prepared by General Applied Science Laboratories for Empire State Electric Energy Research Corp., August 1974, GASL TR 787.

3. Malte, P.C, S., Bernstein, F. Bahlmann, and J. Doelman, NO_x Exhaust Emissions for Gas-Fired Turbine Engines, ASME 90-GT-392, June 1990.

4. Standards Support and Environmental Impact Statement; Volume 1: Proposed Standards of Performance for Stationary Gas Turbines, EPA-450/2-77-017a, September 1977.

5. Hare, C.T. and K.J. Springer, Exhaust Emissions from Uncontrolled Vehicles and Related Equipment using Internal Combustion Engines: Part - 6 Gas Turbines, Electric Utility Power Plant, SWRI for EPA report APTD-1495, U.S. Environmental Protection Agency, Research Triangle Park, NC, NTIS PB-235751.

6. Lieferstein, M., Summary of Emissions from Consolidated Edison Gas Turbine, prepared by the Department of Air Resources, City of New York, November 5, 1975.

7. Hurley, J.F. and S. Hersh, Effect of Smoke and Corrosion Suppressant Additives on Particulate and Gaseous Emissions from Utility Gas Turbine: prepared by KVB Inc., for Electric Power Research Institute, EPRI FP-398, March 1977.

8. Crawford, A.R., E.H. Mannym M.W. Gregory and W. Bartok, The Effect of Combustion Modification on Pollutants and Equipment Performance of Power Generation Equipment," in Proceedings of the Stationary Source Combustion Symposium Vol. III - Field Testing and Surveys, U.S. EPA-600/2-76-152c, NTIS PB-257 146, June 1976.

9. Carl, D.E., E.S. Obidinski, and C.A. Jersey, Exhaust Emissions from a 25-MW Gas Turbine Firing Heavy and Light Distillate Fuel Oils and Natural Gas, paper presented at the Gas Turbine Conference and Products Show, Houston, Texas, March 2-6, 1975.

10. Shareef, G.S. and D.K. Stone, Evaluation of SCR NO_x Controls for Small Natural Gas-Fueled Prime Movers - Phase I, prepared by Radian Corp. (DCN No.: 90-209-028-11) for the Gas Research Institute, GRI-90/0138, July 1990.

11. Pease, R.R., SCAQMD Engineering Division Report - Status Report on SCR for Gas Turbines South Coast Air Quality Management District, July 1984.

12. CEMS Certification and Compliance Testing at Chevron USA, Inc.'s Gaviota Gas Plant, Report PS-89-1837/Project G569-89, Chevron USA, Inc., Goleta, CA, 93117, June 21, 1989.

13. Emission Testing at the Bonneville Pacific Cogeneration Plant, Report PS-92-2702/Project 7141-92, Bonneville Pacific Corporation, Santa Maria, CA, 95434, March 1992.

14. Compliance test report on a production gas-fired IC engine, ESA, 19770-462, Proctor and Gamble, Sacramento, CA, December 1986.

15. Compliance test report on a cogeneration facility, CR 75600-2160, Proctor and Gamble, Sacramento, CA, May, 1990.

16. Larkin, R. and E.B. Higginbotham, Combustion Modification Controls For Stationary Gas Turbines Vol. II. Utility Unit Field Test, EPA 600/7-81-122, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1981.

3.2 HEAVY DUTY NATURAL GAS FIRED PIPELINE COMPRESSOR ENGINES

3.2.1 General

Engines in the natural gas industry are used primarily to power compressors used for pipeline transportation, field gathering (collecting gas from wells), underground storage, and gas processing plant applications, i.e. prime movers. Pipeline engines are concentrated in the major gas producing states (such as those along the Gulf Coast) and along the major gas pipelines. Gas turbines emit considerably smaller amounts of pollutants than do reciprocating engines; however, reciprocating engines are generally more efficient in their use of fuel.

Reciprocating engines are separated into three design classes: 2-stroke lean burn, 4-stroke lean burn and 4-stroke rich burn. Each of these have design differences which affect both baseline emissions as well as the potential for emissions control. Two-stroke engines complete the power cycle in a single engine revolution compared to two revolutions for 4-stroke engines. With the two-stroke engine, the fuel/air charge is injected with the piston near the bottom of the power stroke. The valves are all covered or closed and the piston moves to the top of the cylinder compressing the charge. Following ignition and combustion, the power stroke starts with he downward movement of the piston. Exhaust ports or valves are then uncovered to remove the combustion products, and a new fuel/air charge is ingested. Two stroke engines may be turbocharged using an exhaust powered turbine to pressurize the charge for injection into the cylinder. Non-turbocharged engines may be either blower scavenged or piston scavenged to improve removal of combustion products.

Four stroke engines use a separate engine revolution for the intake/compression stroke and the power/exhaust stroke. These engines may be either naturally aspirated, using the suction from the piston to entrain the air charge, or turbocharged, using a turbine to pressurize the charge. Turbocharged units produce a higher power output for a given engine displacement, whereas naturally aspirated units have lower initial cost and maintenance. Rich burn engines operate near the fuel-air stoichiometric limit with exhaust excess oxygen levels less than 4 percent. Lean burn engines may operate up to the lean flame extinction limit, with exhaust oxygen levels of 12 percent or greater. Pipeline population statistics show a nearly equal installed capacity of turbines and reciprocating engines. For reciprocating engines, two stroke designs contribute approximately two-thirds of installed capacity.

3.2.2 Emissions and Controls

The primary pollutant of concern is NO_x, which readily forms in the high temperature, pressure, and excess air environment found in natural gas fired compressor engines. Lesser amounts of carbon monoxide and hydrocarbons are emitted, although for each unit of natural gas burned, compressor engines (particularly reciprocating engines) emit significantly more of these pollutants than do external combustion boilers. Sulfur oxides emissions are proportional to the sulfur content of the fuel and will usually be quite low because of the negligible sulfur content of most pipeline gas. This section will also discuss the major variables affecting NO_x emissions and the various control technologies that will reduce uncontrolled NO_x emissions.

The major variables affecting NO_x emissions from compressor engines include the air fuel ratio, engine load (defined as the ratio of the operating horsepower to the rated horsepower), intake (manifold) air temperature and absolute humidity. In general, NO_x emissions increase with increasing

load and intake air temperature and decrease with increasing absolute humidity and air fuel ratio. (The latter already being, in most compressor engines, on the "lean" side of that air fuel ratio at which maximum NO_x formation occurs). Quantitative estimates of the effects of these variables are presented in Reference 10.

Because NO_x is the primary pollutant of significance emitted from pipeline compressor engines, control measures to date have been directed mainly at limiting NO_x emissions. Reference 11 summarizes control techniques and emission reduction efficiencies. For gas turbines, the early control applications used water or steam injection. New applications of dry low NO_x combustor can designs and selective catalytic reduction are appearing. Water injection has achieved reductions of 70 to 80 percent with utility gas turbines. Efficiency penalties of 2 to 3 percent are typical due to the added heat load of the water. Turbine power outputs typically increase, however. Steam injection may also be used, but the resulting NO_x reductions may not be as great as with water injection, and it has the added disadvantage that a supply of steam must be readily available. Water injection has not been applied to pipeline compressor engines because of the lack of water availability.

The efficiency penalty and operational impacts associated with water injection have led manufacturers to develop dry low NO_x combustor can designs based on lean burn and/or staging to suppress NO_x formation. These are entering the market in the early 1990's. Stringent gas turbine NO_x limits have been achieved in California in the late 1980's with selective catalytic reduction. This is an ammonia based post-combustion technology which can achieve in excess of 80 percent NO_x reductions. Water or steam injection is frequently used in combination with selective catalytic reduction (SCR) to minimize ammonia costs.

For reciprocating engines, both combustion controls and post-combustion catalytic reduction have been developed. Controlled rich burn engines have mostly been equipped with non-selective catalytic reduction which uses unreacted hydrocarbons and CO to reduce NO_x by 80 to 90 percent. Some rich-burn engines can be equipped with prestratified charge which reduces the peak flame temperature in the NO_x forming regions. Lean burn engines have mostly met NO_x reduction requirements with lean combustion controls using torch ignition or chamber redesign to enhance flame stability. NO_x reductions of 70 to 80 percent are typical for numerous engines with retrofit or new unit controls. Lean burn engines may also be controlled with selective catalytic reductions (SCR), but the operational problems associated with engine control under low NO_x operation have been a deterrent.

Emission factors for natural gas fired pipeline compressor engines are presented in Tables 3.2-1 and 3.2-2 for baseline operation and in 3.2-4 through 3.2-7 for controlled operation. The factors for controlled operation are taken from a single source test. Table 3.2-3 lists non-criteria (organic) emission factors.

TABLE 3.2-1. (ENGLISH UNITS) CRITERIA EMISSION FACTORS FOR UNCONTROLLED NATURAL GAS PRIME MOVERS[a]
(Source Classification Codes)

Pollutant [Rating]	Gas Turbines (SCC 20200201)		2-Cycle Lean Burn (SCC 20200202)		4-Cycle Lean Burn SCC		4-Cycle Rich Burn SCC	
	[grams/hp-hr]	[lb/MMBtu] (fuel input)	[grams/hp-hr]	[lb/MMBtu] (fuel input)	[grams/hp-hr]	[lb/MMBtu] (fuel input)	[grams/hp-hr]	[lb/MMBtu] (fuel input)
NO_x [A]	1.3	.34	11	2.7	12	3.2	10	2.3
CO [A]	.83	.17	1.5	.38	1.6	.42	8.6	1.6
CO_2 [B][b]	405	110	405	110	405	110	405	110
TOC [A]	.18	.053	6.1	1.5	4.9	1.2	1.2	.27
TNMOC [A]	.01	.002	.43	.11	.72	.18	.14	.03
CH_4 [A]	.17	.051	5.6	1.4	4.1	1.1	1.1	.24

[a]Reference 1 - 5. Emission factors are based on entire population. Emission factors for individual engines from specific manufacturers may vary.

[b]Based on 100 percent conversion of the fuel carbon to CO_2. CO_2[lb/MMBtu] = 3.67*C/E, where C = carbon content of fuel by weight (0.7), and E = energy content of fuel, 0.0023 MMBtu/lb. The uncontrolled CO_2 emission factors are also applicable to natural gas prime movers controlled by combustion modifications, NSCR, and SCR.

TABLE 3.2-2. (METRIC UNITS) CRITERIA EMISSION FACTORS FOR UNCONTROLLED NATURAL GAS PRIME MOVERS[a]
(Source Classification Codes)

Pollutant [Rating]	Gas Turbines (SCC 20200201)		2-Cycle Lean Burn (SCC 20200202)		4-Cycle Lean Burn SCC		4-Cycle Rich Burn SCC	
	[grams/ kW-hr]	[ng/J] (fuel input)	[grams/ kW-hr]	[ng/J] (fuel input)	[grams/ kW-hr]	[ng/J] (fuel input)	[grams/ kW-hr]	[ng/J] (fuel input)
NO_x [A]	1.70	145	14.79	1165	15.49	1286	13.46	980
CO [A]	1.11	71	2.04	165	10.29	1195	11.55	697
CO_2 [D][b]	741	47,424	741	47,424	741	47,424	741	47,424
TOC [A]	.24	22.8	8.14	662	5.50	447	1.66	116
TNMOC [A]	.013	.86	.58	47.3	.76	60.2	.19	12.9
CH_4 [A]	.228	21.9	7.56	615	4.73	387	1.48	103

[a]References 1 - 5. Emission factors are based on entire population. Emission factors for individual engines from specific manufacturers may vary.

[b]Based on 100 percent conversion of the fuel carbon to CO_2. CO_2[lb/MMBtu] = 3.67*C/E, where C = carbon content of fuel by weight (0.7), and E = energy content of fuel, 0.0023 MMBtu/lb. The uncontrolled CO_2 emission factors are also applicable to natural gas prime movers controlled by combustion modifications, NSCR, and SCR.

TABLE 3.2-3. (ENGLISH AND METRIC UNITS) NON-CRITERIA EMISSION FACTORS FOR UNCONTROLLED NATURAL GAS PRIME MOVERS[a]
(Source Classification Code: 20200202)

EMISSION FACTOR RATING: E[b]

Pollutant	2-Cycle Lean Burn	
	[grams/kW-hr]	[ng/J]
Formaldehyde	1.78	140
Benzene	2.2E-3	0.17
Toluene	2.2E-3	0.17
Ethylbenzene	1.1E-3	0.086
Xylenes	3.3E-3	0.26

[a]Reference 1.
[b]All emission factor qualities are "E" are due to a very limited data set. "E" rated emission factors may not be applicable to specific facilities or populations.

TABLE 3.2-4. (ENGLISH AND METRIC UNITS) EMISSION FACTORS FOR CONTROLLED NATURAL GAS PRIME MOVERS: COMBUSTION MODIFICATIONS ON TWO-STROKE LEAN BURN ENGINE[a]
(Source Classification Code: 20200202)

EMISSION FACTOR RATING: E[b]

Pollutant	Baseline				Increased A/F Ratio With Intercooling			
	[g/hp-hr]	[g/kW-hr]	[lb/MMBtu]	[ng/J]	[g/hp-hr]	[g/kW-hr]	[lb/MMBtu]	[ng/J]
NO_x	9.9	13	2.9	1300	5.1	6.8	1.5	650
CO	.94	1.3	.28	120	1.5	2.1	.46	200
TOC	7.5	10	2.2	960	8.5	11	2.6	1100
TNMOC	5.2	7.0	1.6	670	6.0	8.1	1.8	780
CH_4	2.3	3.1	.68	290	2.5	3.4	.75	320
PM (total = front+back)	.16	.21	.046	20	.18	.25	.055	24
(solids = front half)	.098	.13	.029	13	.13	.17	.038	16
(condensibles = back half)	.057	.076	.017	7.3	.058	.078	.017	7.3

[a]Reference 6. CO_2 emissions are not affected by control.
[b]All emission factor qualities are "E" due to a very limited data set, for one engine, and may not be accurate for source populations.

TABLE 3.2-5. (ENGLISH AND METRIC UNITS) EMISSION FACTORS FOR CONTROLLED NATURAL GAS PRIME MOVERS: NSCR ON FOUR-CYCLE RICH BURN ENGINE[a]

EMISSION FACTOR RATING: E[b]

Pollutant	Inlet				Outlet			
	[g/hp-hr]	[g/kW-hr]	[lb/MMBtu]	[ng/J]	[g/hp-hr]	[g/kW-hr]	[lb/MMBtu]	[ng/J]
NO_x	7.8	10	1.8	770	2.5	3.4	.58	250
CO	12	16	2.8	1208	10	14	2.4	1000
TOC	.33	.44	.079	33.97	.2	.27	.047	20
NH_3	.05	.07	.012	5.16	.82	1.10	.19	82
C7 -> C16	.019	.026	.0042	1.81	.0041	.0055	.0009	.39
C16+	.017	.029	.004	1.72	.0006	.0008	.0001	.043
PM (solids = front half)	.003	.004	.0007	.301	.003	.004	.0007	.30
Benzene			7.1EE4	.31			1.1E-4	.047
Toluene			2.3EE4	.099			<2.3E-5	.0099
Xylenes			<5.9E-5	.025			<4E-5	.017
Propylene			<1.6E-4	.069			<1.6E-4	.069
Naphthalene			<4.9E-5	.021			<4.9E-5	.021
Formaldehyde			<1.6E-3	.69			<7.2E-6	.003
Acetaldehyde			<6.1E-5	.026			<4.8E-6	.0021
Acrolein			<3.7E-5	.016			<9.6E-6	.0041

[a]Reference 7 (criteria pollutants) and Reference 4 (air toxics).

[b]All emission factors are rated "E" due to a very limited data set. "E" rated emission factors may not be applicable to specific facilities or populations.

TABLE 3.2-6. (ENGLISH AND METRIC UNITS) EMISSION FACTORS FOR CONTROLLED NATURAL GAS PRIME MOVERS: SCR ON FOUR-CYCLE LEAN BURN ENGINE[a]

EMISSION FACTOR RATING: E[b]

Pollutant	Inlet				Outlet			
	[g/hp-hr]	[g/kW-hr]	[lb/MMBtu]	[ng/J]	[g/hp-hr]	[g/kW-hr]	[lb/MMBtu]	[ng/J]
NO_x	19	26	6.4	2800	3.6	4.8	1.2	510
CO	1.2	1.6	.38	160	1.1	1.5	.37	160
NH_3					.27	.36	.091	39
C7 -> C16	.007	.009	.0023	.99	.0031	.0042	.0013	.56
C16+	.013	.017	.0044	1.9	.0024	.0032	.0008	.34

[a]Reference 8. CO_2 emissions are not affected by control.
[b]All emission factor qualities are "E" due to a very limited data set. "E" rated emission factors may not be applicable to specific facilities or populations.

TABLE 3.2-7 (ENGLISH AND METRIC UNITS) EMISSION FACTORS FOR CONTROLLED NATURAL GAS PRIME MOVERS: "PCC" AND "CLEAN BURN" ON TWO-CYCLE LEAN BURN ENGINE[a]
(Source Classification Code: 20200202)

EMISSION FACTOR RATING: C

Pollutant	"CleanBurn"				"PreCombustion Chamber"			
	[g/hp-hr]	[g/kW-hr]	[lb/MMBtu]	[ng/J]	[g/hp-hr]	[g/kW-hr]	[lb/MMBtu]	[ng/J]
NO_x	2.3	3.1	.83	360	2.9	3.9	.85	370
CO	1.1	1.5	.30	130	2.4	3.3	.67	290
TOC	2.5	3.4	.77	330	6.4	8.6	1.8	760
TNMOC	.12	.16	.15	65	.88	1.2	.25	110
CH_4	2.4	3.3	.62	260	5.5	7.4	1.5	650

[a]Reference 9. CO_2 emissions are not affected by control.

References for Section 3.2

1. Engines, Turbines, and Compressors Directory, American Gas Association, Catalog #XF0488.

2. Martin, N.L. and R.H. Thring, Computer Database of Emissions Data for Stationary Reciprocating Natural Gas Engines and Gas Turbines in use by the Gas Pipeline Transmission Industry Users Manual (Electronic Database Included), prepared by SouthWest Research Institute for the Gas Research Institute, GRI-89/0041.

3. Air Pollution Source Testing for California AB2588 on an Oil Platform Operated by Chevron USA, Inc. Platform Hope, California, Chevron USA, Inc., Ventura, CA, August 29, 1990.

4. Air Pollution Source Testing for California AB2588 of Engines at the Chevron USA, Inc. Carpinteria Facility, Chevron USA, Inc., Ventura, CA, August 30, 1990.

5. Pooled Source Emission Test Report: Gas Fired IC Engines in Santa Barbara County, ARCO, Bakersfield, CA, July, 1990.

6. Castaldini, C., Environmental Assessment of NO_x Control on a Spark-Ignited Large Bore Reciprocating Internal Combustion Engine, U.S. Environmental Protection Agency, Research Triangle Park, NC, April 1984.

7. Castaldini, C. and L.R. Waterland, Environmental Assessment of a Reciprocating Engine Retrofitted with Nonselective Catalytic Reduction, EPA-600/7-84-073B, U.S. Environmental Protection Agency, Research Triangle Park, NC, June 1984.

8. Castaldini, C. and L.R. Waterland, Environmental Assessment of a Reciprocating Engine Retrofitted with Selective Catalytic Reduction, EPA Contract No. 68-02-3188, U.S. Environmental Protection Agency, Research Triangle Park, NC, December 1984.

9. Fanick, R.E., H.E. Dietzmann, and C.M. Urban, Emissions Data for Stationary Reciprocating Engines and Gas Turbines in Use by the Gas Pipeline Transmission Industry - Phase I&II, prepared by SouthWest Research Institute for the Pipeline Research Committee of the American Gas Association, April 1988, Project PR-15-613.

10. Standards Support and Environmental Impact Statement, Volume I: Stationary Internal Combustion Engines, EPA-450/2-78-125a, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, July 1979.

11. Castaldini, C., NO_x Reduction Technologies for Natural Gas Industry Prime Movers, prepared by Acurex Corp., for the Gas Research Institute, GRI-90/0215, August 1990.

3.3 GASOLINE AND DIESEL INDUSTRIAL ENGINES

3.3.1 General

The engine category addressed by this section covers a wide variety of industrial applications of both gasoline and diesel internal combustion engines such as, aerial lifts, fork lifts, mobile refrigeration units, generators, pumps, industrial sweepers/scrubbers, material handling equipment (such as conveyors), and portable well-drilling equipment. The rated power of these engines covers a rather substantial range; up to 186 kW (250 hp) for gasoline engines and up to 447 kW (600 hp) for diesel engines. (Diesel engines greater than 600 hp are covered in Section 3.4: Large Stationary Diesel and All Stationary Dual Fuel Engines). Understandably, substantial differences in engine duty cycles exist. It was necessary, therefore, to make reasonable assumptions concerning usage in order to formulate some of the emission factors.

3.3.2 Process Description

All reciprocating internal combustion (IC) engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are two methods used for stationary reciprocating IC engines: compression ignition (CI) and spark ignition (SI). Section 3.3 deals with both types of reciprocating internal combustion engines.

In compression ignition engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous as the air is above the auto-ignition temperature of the fuel. Spark ignition engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder. All diesel fueled engines are compression ignited and all gasoline fueled engines are spark ignited.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature auto-ignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.

3.3.3 Emissions and Controls

The best method for calculating emissions is on the basis of "brake specific" emission factors (g/hp-hr or g/kW-hr). Emissions are calculated by taking the product of the brake specific emission factor, the usage in hours (that is, hours per year or hours per day), the power available (rated power), and the load factor (the power actually used divided by the power available).

Once reasonable usage and duty cycles for this category were ascertained, emission values were aggregated to arrive at the factors presented in Tables 3.3-1 (English units) and 3.3-2 (Metric units) for criteria and organic pollutants. Emissions data for a specific design type were weighted according to estimated material share for industrial engines. The emission factors in this table are most appropriately applied to a population of industrial engines rather than to an individual power plant because of their aggregate nature. Table 3.3-3 shows unweighted speciated organic compound and air toxic emissions factors based upon only two engines. Their inclusion in this section is intended only for rough order of magnitude estimates.

Table 3.3-4 shows a summary of various diesel emission reduction technologies (some which may be applicable to gasoline engines). These technologies are categorized into fuel modifications, engine modifications, and exhaust after treatments. Current data are insufficient to quantify the results of the modifications. Table 3.3-4 provides general information on the trends of changes on selected parameters.

TABLE 3.3-1. (ENGLISH UNITS) EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES[a]
(Source Classification Codes)

Pollutant [Rating][b]	Gasoline Fuel (SCC 20200301, 20300301)		Diesel Fuel (SCC 20200102, 20300101)	
	[grams/hp-hr] (power output)	[lb/MMBtu] (fuel input)	[grams/hp-hr] (power output)	[lb/MMBtu] (fuel input)
NO_x [D]	5.16	1.63	14.0	4.41
CO [D]	199	62.7	3.03	0.95
SO_x [D]	0.268	0.084	0.931	0.29
Particulate [D]	0.327	0.10	1.00	0.31
CO_2 [B][c]	493	155	525	165
Aldehydes [D]	0.22	0.07	0.21	0.07
Hydrocarbons				
Exhaust [D]	6.68	2.10	1.12	0.35
Evaporative [E]	0.30	0.09	0.00	0.00
Crankcase [E]	2.20	0.69	0.02	0.01
Refueling [E]	0.49	0.15	0.00	0.00

[a]Data based on uncontrolled levels for each fuel from References 1, 3 and 6. When necessary, the average brake specific fuel consumption (BSFC) value was used to convert from g/hp-hr to lb/MMBtu was 7000 Btu/hp-hr.

[b]"D" and "E" rated emission factors are most appropriate when applied to a population of industrial engines rather than to an individual power plant, due to the aggregate nature of the emissions data.

[c]Based on assumed 100 percent conversion of carbon in fuel to CO_2 with 87 weight percent carbon in diesel, 86 weight percent carbon in gasoline, average brake specific fuel consumption of 7000 Btu/hp-hr, diesel heating value of 19300 Btu/lb, and gasoline heating value of 20300 Btu/lb.

TABLE 3.3-2. (METRIC UNITS) EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES[a]
(Source Classification Codes)

Pollutant [Rating][b]	Gasoline Fuel (SCC 20200301, 20300301)		Diesel Fuel (SCC 20200102, 20300101)	
	[grams/kW-hr] (power output)	[ng/J] (fuel input)	[grams/kW-hr] (power output)	[ng/J] (fuel input)
NO_x [D]	6.92	699	18.8	1,896
CO [D]	267	26,947	4.06	410
SO_x [D]	0.359	36	1.25	126
Particulate [D]	0.439	44	1.34	135
CO_2 [B][c]	661	66,787	704	71,065
Aldehydes [D]	0.30	29	0.28	28
Hydrocarbons				
Exhaust [D]	8.96	905	1.50	152
Evaporative [E]	0.40	41	0.00	0.00
Crankcase [E]	2.95	298	0.03	2.71
Refueling [E]	0.66	66	0.00	0.00

[a]Data based on uncontrolled levels for each fuel from References 1, 3 and 6.
[b]"D" and "E" rated emission factors are most appropriate when applied to a population of industrial engines rather than to an individual power plant, due to the aggregate nature of the emissions data.
[c]Based on assumed 100 percent conversion of carbon in fuel to CO_2 with 87 weight percent carbon in diesel, 86 weight percent carbon in gasoline, average brake specific fuel consumption of 7000 Btu/hp-hr, diesel heating value of 19300 Btu/lb, and gasoline heating value of 20300 Btu/lb.

TABLE 3.3-3. (ENGLISH AND METRIC UNITS) SPECIATED ORGANIC COMPOUNDS AND AIR TOXIC EMISSION FACTORS FOR UNCONTROLLED DIESEL ENGINES[a]
(Source Classification Codes: 20200102, 20300101)

(ALL EMISSION FACTORS ARE RATED: E)[b]

Pollutant	[lb/MMBtu] (fuel input)	[ng/J] (fuel input)
Benzene	9.33 E-04	0.401
Toluene	4.09 E-04	0.176
Xylenes	2.85 E-04	0.122
Propylene	2.58 E-03	1.109
1,3 Butadiene[c]	< 3.91 E-05	< 0.017
Formaldehyde	1.18 E-03	0.509
Acetaldehyde	7.67 E-04	0.330
Acrolein	< 9.25 E-05	< 0.040
Polycyclic Aromatic Hydrocarbons (PAH)		
Naphthalene	8.48 E-05	3.64 E-02
Acenaphthylene	< 5.06 E-06	< 2.17 E-03
Acenaphthene	< 1.42 E-06	< 6.11 E-04
Fluorene	2.92 E-05	1.26 E-02
Phenanthrene	2.94 E-05	1.26 E-02
Anthracene	1.87 E-06	8.02 E-04
Fluoranthene	7.61 E-06	3.27 E-03
Pyrene	4.78 E-06	2.06 E-03
Benz(a)anthracene	1.68 E-06	7.21 E-04
Chrysene	3.53 E-07	1.52 E-04
Benzo(b)fluoranthene	< 9.91 E-08	< 4.26 E-05
Benzo(k)fluoranthene	< 1.55 E-07	< 6.67 E-05
Benzo(a)pyrene	< 1.88 E-07	< 8.07 E-05
Indeno(1,2,3-cd)pyrene	< 3.75 E-07	< 1.61 E-04
Dibenz(a,h)anthracene	< 5.83 E-07	< 2.50 E-04
Benzo(g,h,l)perylene	< 4.89 E-07	< 2.10 E-04
Total PAH	1.68 E-04	7.22 E-02

[a]Data are based on the uncontrolled levels of two diesel engines from References 6 and 7.
[b]"E" rated emission factors are due to limited data sets, inherent variability in the population and/or a lack of documentation of test results. "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.
[c]Data are based on one engine.

TABLE 3.3-4. DIESEL EMISSION CONTROL TECHNOLOGIES[a]

Technology	Affected Parameter[b]	
	Increase	Decrease
Fuel Modifications		
Sulfur Content Increase	PM, Wear	
Aromatic Content Increase	PM, NO_x	
Cetane Number		PM, NO_x
10 percent and 90 percent Boiling Point		PM
Fuel Additives		PM, NO_x
Water/Fuel Emulsions		NO_x
Engine Modifications		
Injection Timing	NO_x, PM, BSFC, Power	NO_x
Fuel Injection Pressure	PM, NO_x	
Injection Rate Control		NO_x, PM
Rapid Spill Nozzles		PM
Electronic Timing & Metering		NO_x, PM
Injector Nozzle Geometry		PM
Combustion Chamber Modifications		NO_x, PM
Turbocharging	PM, Power	NO_x
Charge Cooling		NO_x
Exhaust Gas Recirculation	PM, Power, Wear	NO_x
Oil Consumption Control		PM, Wear
Exhaust After Treatment		
Particulate Traps		PM
Selective Catalytic Reduction		NO_x
Oxidation Catalysts		HC, CO, PM

[a]Reference 4.
[b]NO_x = Nitrogen oxides; PM = Particulate matter; HC = Hydrocarbons; CO = Carbon monoxide; BSFC = Brake specific fuel consumption.

References for Section 3.3

1. Hare, C.T. and K.J. Springer, Exhaust Emissions from Uncontrolled Vehicles and Related Equipment using Internal Combustion Engines, Part 5: Farm, Construction, and Industrial Engines, U.S. Environmental Protection Agency, Research Triangle Park, NC, Publication APTD-1494, October 1973, pp. 96-101.

2. Lips, H.I., J.A. Gotterba, and K.J. Lim, Environmental Assessment of Combustion Modification Controls for Stationary Internal Combustion Engines, EPA-600/7-81-127, Industrial Environmental Research Laboratory, Office of Environmental Engineering and Technology, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1981.

3. Standards Support and Environmental Impact Statement, Volume I: Stationary Internal Combustion Engines, EPA-450/2-78-125a, Emission Standards and Engineering Division, Office of Air, Noise, and Radiation, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1979.

4. Technical Feasibility of Reducing NO_x and Particulate Emissions from Heavy-Duty Engines, Draft Report by Acurex Environmental Corporation for the California Air Resources Board, Sacramento, CA, March 1992, CARB Contract A132-085.

5. Nonroad Engine and Vehicle Emission Study-Report, EPA-460/3-91-02, Certification Division, Office of Mobile Sources, Office of Air & Radiation, U.S. Environmental Protection Agency, Research Triangle Park, NC, November 1991.

6. Pooled Source Emission Test Report: Oil and Gas Production Combustion Sources, Fresno and Ventura Counties, California, Report prepared by ENSR Consulting and Engineering for Western States Petroleum Association (WSPA), Bakersfield, CA, December 1990, ENSR 7230-007-700.

7. Osborn, W.E., and M.D. McDannel, Emissions of Air Toxic Species: Test Conducted Under AB2588 for the Western States Petroleum Association, Report prepared by Carnot for Western States Petroleum Association (WSPA), Glendale, CA, May 1990, CR 72600-2061.

3.4 LARGE STATIONARY DIESEL AND ALL STATIONARY DUAL FUEL ENGINES

3.4.1 General

The primary domestic use of large stationary diesel engines (greater than 600 hp) is in oil and gas exploration and production. These engines, in groups of three to five, supply mechanical power to operate drilling (rotary table), mud pumping and hoisting equipment, and may also operate pumps or auxiliary power generators. Another frequent application of large stationary diesels is electricity generation for both base and standby service. Smaller uses include irrigation, hoisting and nuclear power plant emergency cooling water pump operation.

Dual fuel engines were developed to obtain compression ignition performance and the economy of natural gas, using a minimum of 5 to 6 percent diesel fuel to ignite the natural gas. Large dual fuel engines have been used almost exclusively for prime electric power generation. This section includes all dual fuel engines.

3.4.2 Process Description

All reciprocating internal combustion (IC) engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are two methods used for stationary reciprocating IC engines: compression ignition (CI) and spark ignition (SI). Section 3.4 deals only with compression ignition engines.

In compression ignition engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous as the air is above the auto-ignition temperature of the fuel. Spark ignition engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder. Although all diesel fueled engines are compression ignited and all gasoline and gas fueled engines are spark ignited, gas can be used in a compression ignition engine if a small amount of diesel fuel is injected into the compressed gas/air mixture to burn any mixture ratio of gas and diesel oil (hence the name dual fuel), from 6- to 100-percent diesel oil.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature auto-ignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.

3.4.3 Emissions and Controls

Most of the pollutants from IC engines are emitted through the exhaust. However, some hydrocarbons escape from the crankcase as a result of blowby (gases which are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor because of evaporation. Nearly all of the hydrocarbons from diesel compression ignition (CI) engines enter the atmosphere from the exhaust. Crankcase blowby is minor because hydrocarbons are not present during compression of the charge. Evaporative losses are insignificant in diesel engines due to the low volatility of diesel fuels. In general, evaporative losses are also negligible in engines using gaseous fuels because these engines receive their fuel continuously from a pipe rather than via a fuel storage tank and fuel pump.

The primary pollutants from internal combustion engines are oxides of nitrogen (NO_x), organic compounds (hydrocarbons), carbon monoxide (CO), and particulates, which include both visible (smoke) and nonvisible emissions. The other pollutants are primarily the result of incomplete combustion. Ash and metallic additives in the fuel also contribute to the particulate content of the exhaust. Oxides of sulfur (SO_x) also appears in the exhaust from IC engines.

The primary pollutant of concern from large stationary diesel and all stationary dual fuel engines is NO_x, which readily forms in the high temperature, pressure, nitrogen content of the fuel, and excess air environment found in these engines. Lesser amounts of CO and organic compounds are emitted. The sulfur compounds, mainly SO_2, are directly related to the sulfur content of the fuel. SO_x emissions will usually be quite low because of the negligible sulfur content of diesel fuels and natural gas.

Tables 3.4-1 (English units) and 3.4-2 (Metric units) contain gaseous emission factors.

Table 3.4-3 shows the speciated organic compound emission factors and Table 3.4-4 shows the emission factors for polycyclic aromatic hydrocarbons (PAH). These tables do not provide a complete speciated organic compound and PAH listing since they are based only on a single engine test; they are to be used for rough order of magnitude comparisons.

Table 3.4-5 shows the particulate and particle sizing emission factors.

Control measures to date have been directed mainly at limiting NO_x emissions because NO_x is the primary pollutant from diesel and dual fuel engines. Table 3.4-6 shows the NO_x reduction and fuel consumption penalties for diesel and dual fueled engines based on some of the available control techniques. All of these controls are engine control techniques except for the selective catalytic reduction (SCR) technique, which is a post-combustion control. The emission reductions shown are those which have been demonstrated. The effectiveness of controls on an particular engine will depend on the specific design of each engine and the effectiveness of each technique could vary considerably. Other NO_x control techniques exist but are not included in Table 3.4-6. These techniques include internal/external exhaust gas recirculation (EGR), combustion chamber modification, manifold air cooling, and turbocharging.

TABLE 3.4-1. (ENGLISH UNITS) GASEOUS EMISSION FACTORS FOR LARGE STATIONARY DIESEL AND ALL STATIONARY DUAL FUEL ENGINES[a]
(Source Classification Codes)

Pollutant	Diesel Fuel (SCC 20200401)			Dual Fuel[b] (SCC 20200402)		
	[grams/hp-hr] (power output)	[lb/MMBtu] (fuel input)	Emission Factor Rating[c]	[grams/hp-hr] (power output)	[lb/MMBtu] (fuel input)	Emission Factor Rating[c]
NO_x	11	3.1	C	9.2	3.1	D
CO	2.4	0.81	C	2.3	0.79	D
SO_x[d]	$3.67S_1$	$1.01S_1$	B	$0.184S_1 + 4.34S_2$	$0.05S_1 + 0.895S_2$	B
CO_2[e]	524	165	B	350	110	B
TOC,[f] (as CH_4)	0.32	0.09	C	2.4	0.8	D
Methane	0.03	0.01	E[g]	1.8	0.6	E[h]
Nonmethane	0.33	0.10	E[g]	0.6	0.2	E[h]

[a]Data are based on uncontrolled levels for each fuel from references 4, 5, and 6. When necessary, the average heating value of diesel was assumed to be 19300 Btu/lb with a density of 7.1 lb/gal. The power output and fuel input values were averaged independently from each other due to the use of actual Brake Specific Fuel Consumption values for each data point and the use of data that may have enough information to calculate only one of the two emission factors (e.g., if there was enough information to calculate lb/MMBtu, but not enough to calculate the g/hp-hr). The emission factors are based on averages across all manufacturers and duty cycles. The actual emissions from a particular engine or manufacturer could vary considerably from these levels.

[b]Dual fuel is based on a mixture of 95 percent natural gas and 5 percent diesel fuel.

[c]"D" and "E" rating for emission factors are due to limited data sets, inherent variability in the population and/or a lack of documentation of test results. "D" and "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.

[d]Emission factors are based on the assumption that all sulfur in the fuel is converted to SO_2. S_1 = percent sulfur in diesel fuel; S_2 = percent sulfur in gas.

[e]Based on assumed 100 percent conversion of carbon in fuel to CO_2 with 87 weight percent carbon in diesel, 70 weight percent carbon in natural gas, dual fuel mixture of 5 percent diesel with 95 percent natural gas, average brake specific fuel consumption of 7000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and natural gas heating value of 23,900 Btu/lb.

[f]Total Organic Compounds.

[g]Based on emissions data from one engine.

[h]Based on the assumption that nonmethane organic compounds are 25 percent of TOC emissions from dual fuel engines. Molecular weight of nonmethane gas stream is assumed to be that of methane.

TABLE 3.4-2. (METRIC UNITS) GASEOUS EMISSION FACTORS FOR LARGE STATIONARY DIESEL AND ALL STATIONARY DUAL FUEL ENGINES[a]
(Source Classification Codes)

Pollutant	Diesel Fuel (SCC 20200401)			Dual Fuel[b] (SCC 20200402)		
	[g/kW-hr] (power output)	[ng/J] (fuel input)	Emission Factor Rating[c]	[g/kW-hr] (power output)	[ng/J] (fuel input)	Emission Factor Rating[c]
NO_x	14	1,322	C	12.3	1,331	D
CO	3.2	349	C	3.1	340	D
SO_x[d]	$4.92S_1$	$434S_1$	B	$0.25S_1 + 4.34S_1$	$21.7S_1 + 384S_2$	B
CO_2[e]	703	70,942	B	469	47,424	B
TOC,[f] (as CH_4)	0.43	38	C	3.2	352	D
Methane	0.04	4	E[g]	2.4	240	E[h]
Nonmethane	0.44	45	E[g]	0.8	80	E[h]

[a]Data are based on uncontrolled levels for each fuel from references 4, 5, and 6. When necessary, the average heating value of diesel was assumed to be 19300 Btu/lb with a density of 7.1 lb/gal. The power output and fuel input values were averaged independently from each other due to the use of actual Brake Specific Fuel Consumption values for each data point and the use of data that may have enough information to calculate only one of the two emission factors (e.g., if there was enough information to calculate lb/MMBtu, but not enough to calculate the g/hp-hr). The emission factors are based on averages across all manufacturers and duty cycles. The actual emissions from a particular engine or manufacturer could vary considerably from these levels.

[b]Dual fuel is based on 95 percent natural gas and 5 percent diesel fuel.

[c]"D" and "E" rating for emission factors are due to limited data sets, inherent variability in the population and/or a lack of documentation of test results. "D" and "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.

[d]Emission factors are based on the assumption that all sulfur in the fuel is converted to SO_2. S_1 = percent sulfur in fuel oil; S_2 = percent sulfur in gas.

[e]Based on assumed 100 percent conversion of carbon in fuel to CO_2 with 87 weight percent carbon in diesel, 70 weight percent carbon in natural gas, dual fuel mixture of 5 percent diesel with 95 percent natural gas, average brake specific fuel consumption of 7000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and natural gas heating value of 23,900 Btu/lb.

[f]Total Organic Compounds.

[g]Based on emissions data from one engine.

[h]Based on the assumption that nonmethane organic compounds are 25 percent of TOC emissions from dual fuel engines. Molecular weight of nonmethane gas stream is assumed to be that of methane.

TABLE 3.4-3. (ENGLISH AND METRIC UNITS) SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR LARGE STATIONARY DIESEL ENGINES[a]
(*Source Classification Code: 20200401*)

(Emission Factor Rating: E)[b]

Pollutant	[lb/MMBtu] (fuel input)	[ng/J] (fuel input)
Benzene	7.76 E-04	3.34 E-01
Toluene	2.81 E-04	1.21 E-01
Xylenes	1.93 E-04	8.30 E-02
Propylene	2.79 E-03	1.20 E-00
Formaldehyde	7.89 E-05	3.39 E-02
Acetaldehyde	2.52 E-05	1.08 E-02
Acrolein	7.88 E-06	3.39 E-03

[a]Data based on the uncontrolled levels of one diesel engine from reference 5. There was enough information to compute the input specific emission factors of lb/MMBtu, but not enough to calculate the output specific emission factor of g/hp-hr. There was enough information to compute the input specific emission factors of ng/J, but not enough to calculate the output specific emission factor of g/kW-hr.

[b]"E" rating for emission factors are due to limited data sets, inherent variability in the population and/or a lack of documentation of test results. "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.

TABLE 3.4-4. (ENGLISH AND METRIC UNITS) POLYCYCLIC AROMATIC HYDROCARBON (PAH) EMISSION FACTORS FOR LARGE STATIONARY DIESEL ENGINES[a]
(Source Classification Code: 20200401)

(Emission Factor Rating: E)[b]

Pollutant	[lb/MMBtu] (fuel input)	[ng/J] (fuel input)
Polycyclic Aromatic Hydrocarbons (PAH)		
Naphthalene	1.30 E-04	5.59 E-02
Acenaphthylene	9.23 E-06	3.97 E-03
Acenaphthene	4.68 E-06	2.01 E-03
Fluorene	1.28 E-05	5.50 E-03
Phenanthrene	4.08 E-05	1.75 E-02
Anthracene	1.23 E-06	5.29 E-04
Fluoranthene	4.03 E-06	1.73 E-03
Pyrene	3.71 E-06	1.60 E-03
Benz(a)anthracene	6.22 E-07	2.67 E-04
Chrysene	1.53 E-06	6.58 E-04
Benzo(b)fluoranthene	1.11 E-06	4.77 E-04
Benzo(k)fluoranthene	< 2.18 E-07	< 9.37 E-05
Benzo(a)pyrene	< 2.57 E-07	< 1.10 E-04
Indeno(1,2,3-cd)pyrene	< 4.14 E-07	< 1.78 E-04
Dibenz(a,h)anthracene	< 3.46 E-07	< 1.49 E-04
Benzo(g,h,l)perylene	< 5.56 E-07	< 2.39 E-04
Total PAH	2.12 E-04	9.09 E-02

[a]Data are based on the uncontrolled levels of one diesel engine from reference 5. There was enough information to compute the input specific emission factors of lb/MMBtu and ng/J but not enough to calculate the output specific emission factor of g/hp-hr and g/kW-hr.

[b]"E" rating for emission factors is due to limited data sets, inherent variability in the population and/or a lack of documentation of test results. "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.

TABLE 3.4-5. (ENGLISH AND METRIC UNITS) PARTICULATE AND PARTICLE SIZING EMISSION FACTORS FOR LARGE STATIONARY DIESEL ENGINES[a]
(Source Classification Code: 20200401)

(Emission Factor Rating: E)[b]

Pollutant	Power Output		Fuel Input	
	[grams/hp-hr]	[grams/kW-hr]	[lb/MMBtu]	[ng/J]
Particulate Size Distribution				
<1 μm	0.1520	0.2038	0.0478	20.56
1-3 μm	0.0004	0.0005	0.0001	0.05
3-10 μm	0.0054	0.0072	0.0017	0.73
>10 μm	0.0394	0.0528	0.0124	5.33
Total PM-10 (≤10 μm)	0.1578	0.2116	0.0496	21.34
TOTAL	0.1972	0.2644	0.0620	26.67
Particulate Emissions				
Solids	0.2181	0.2925	0.0686	29.49
Condensables	0.0245	0.0329	0.0077	3.31
TOTAL	0.2426	0.3253	0.0763	32.81

[a]Data are based on the uncontrolled levels of one diesel engine from reference 6. The data for the particulate emissions were collected using Method 5 and the particle size distributions were collected using a Source Assessment Sampling System (SASS).

[b]"E" rating for emission factors is due to limited data sets, inherent variability in the population and/or a lack of documentation of test results. "E" rated emission factors may not be suitable for specific facilities or populations and should be used with care.

TABLE 3.4-6. NO_x REDUCTION AND FUEL CONSUMPTION PENALTIES FOR LARGE STATIONARY DIESEL AND DUAL FUEL ENGINES[a]
(Source Classification Codes)

Control Approach		Diesel (SCC 20200401)		Dual Fuel (SCC 20200402)	
		Percent NO_x Reduction	ΔBSFC,[b] Percent	Percent NO_x Reduction	ΔBSFC,[b] Percent
Derate	10%			<20	4
	20%	<20	4		
	25%	5-23	1-5	1-33	1-7
Retard	2°	<20	4	<20	3
	4°	<40	4	<40	1
	8°	28-45	2-8	50-73	3-5
Air-to-Fuel	3%			<20	0
	±10%	7-8	3	25-40	1-3
Water Injection (H_2O/fuel ratio)	50%	25-35	2-4		
Selective Catalytic Reduction (SCR)		80-95	0	80-95	0

[a]Data are based on references 1, 2, and 3. The reductions shown are typical and will vary depending on the engine and duty cycle.
[b]BSFC = Brake Specific Fuel Consumption.

References for Section 3.4

1. Lips, H.I., J.A. Gotterba, and K.J. Lim, Environmental Assessment of Combustion Modification Controls for Stationary Internal Combustion Engines, EPA-600/7-81-127, Industrial Environmental Research Laboratory, Office of Environmental Engineering and Technology, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1981,

2. Campbell, L.M., D.K. Stone, and G.S. Shareef, Sourcebook: NO_x Control Technology Data, Control Technology Center, EPA-600/2-91-029, Emission Standards Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1991.

3. Catalysts for Air Pollution Control, brochure by the Manufacturers of Emission Controls Association (MECA), Washington, DC, March 1992.

4. Standards Support and Environmental Impact Statement, Volume I: Stationary Internal Combustion Engines, EPA-450/2-78-125a, Emission Standards and Engineering Division, Office of Air, Noise, and Radiation, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1979.

5. Pooled Source Emission Test Report: Oil and Gas Production Combustion Sources, Fresno and Ventura Counties, California, Report prepared by ENSR Consulting and Engineering for Western States Petroleum Association (WSPA), Bakersfield, CA, December 1990, ENSR # 7230-007-700.

6. Castaldini, C., Environmental Assessment of NO_x Control on a Compression Ignition Large Bore Reciprocating Internal Combustion Engine, Volume I: Technical Results, EPA-600/7-86/001a, Combustion Research Branch of the Energy Assessment and Control Division, Industrial Environmental Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, Washington, DC, April 1984.

5.2 SYNTHETIC AMMONIA

5.2.1 General[1-2]

Synthetic ammonia (NH_3) refers to ammonia that has been synthesized (SIC 2873) from natural gas. Natural gas molecules are reduced to carbon and hydrogen. The hydrogen is then purified and reacted with nitrogen to produce ammonia. Approximately 75 percent of the ammonia produced is used as fertilizer, either directly as ammonia or indirectly after synthesis as urea, ammonium nitrate, and monoammonium or diammonium phosphates. The remaining is used as raw material in the manufacture of polymeric resins, explosives, nitric acid, and other products.

Synthetic ammonia plants are located throughout the U. S. and Canada. Synthetic ammonia is produced in 25 states by 60 plants which have an estimated combined annual production capacity of 15.9 million megagrams (17.5 million tons) in 1991. Ammonia plants are concentrated in areas with abundant supplies of natural gas. Seventy percent of U. S. capacity is located in Louisiana, Texas, Oklahoma, Iowa and Nebraska.

5.2.2 Process Description[1,3-4]

Anhydrous ammonia is synthesized by reacting hydrogen with nitrogen at a molar ratio of 3 to 1, then compressing the gas and cooling it to -33°C (-27°F). Nitrogen is obtained from the air, while hydrogen is obtained from either the catalytic steam reforming of natural gas (methane) or naphtha, or the electrolysis of brine at chlorine plants. In the U. S., about 98 percent of synthetic ammonia is produced by catalytic steam reforming of natural gas. Figure 5.2-1 shows a general process flow diagram of a typical ammonia plant.

Six process steps are required to produce synthetic ammonia using the catalytic steam reforming method: 1) natural gas desulfurization, 2) catalytic steam reforming, 3) carbon monoxide shift, 4) carbon dioxide removal, 5) methanation and 6) ammonia synthesis. The first, third, fourth, and fifth steps remove impurities such as sulfur, CO, CO_2 and water from the feedstock, hydrogen and synthesis gas streams. In the second step, hydrogen is manufactured and nitrogen (air) is introduced into this two stage process. The sixth step produces anhydrous ammonia from the synthetic gas. While all ammonia plants use this basic process, details such as operating pressures, temperatures, and quantities of feedstock vary from plant to plant.

5.2.2.1 Natural Gas Desulfurization

In this step, the sulfur content (as H_2S) in natural gas is reduced to below 280 micrograms per cubic meter to prevent poisoning of the nickel catalyst in the primary reformer. Desulfurization can be accomplished by using either activated carbon or zinc oxide. Over 95 percent of the ammonia plants in the U. S. use activated carbon fortified with metallic oxide additives for feedstock desulfurization. The remaining plants use a tank filled with zinc oxide for desulfurization. Heavy hydrocarbons can decrease the effectiveness of an activated carbon bed. This carbon bed also has another disadvantage in that it cannot remove carbonyl sulfide. Regeneration of carbon is accomplished by passing superheated steam through the carbon bed. A zinc oxide bed offers several advantages over the activated carbon bed. Steam regeneration to use as energy is not required when using a zinc oxide bed. No air emissions are created by the zinc oxide bed, and the higher

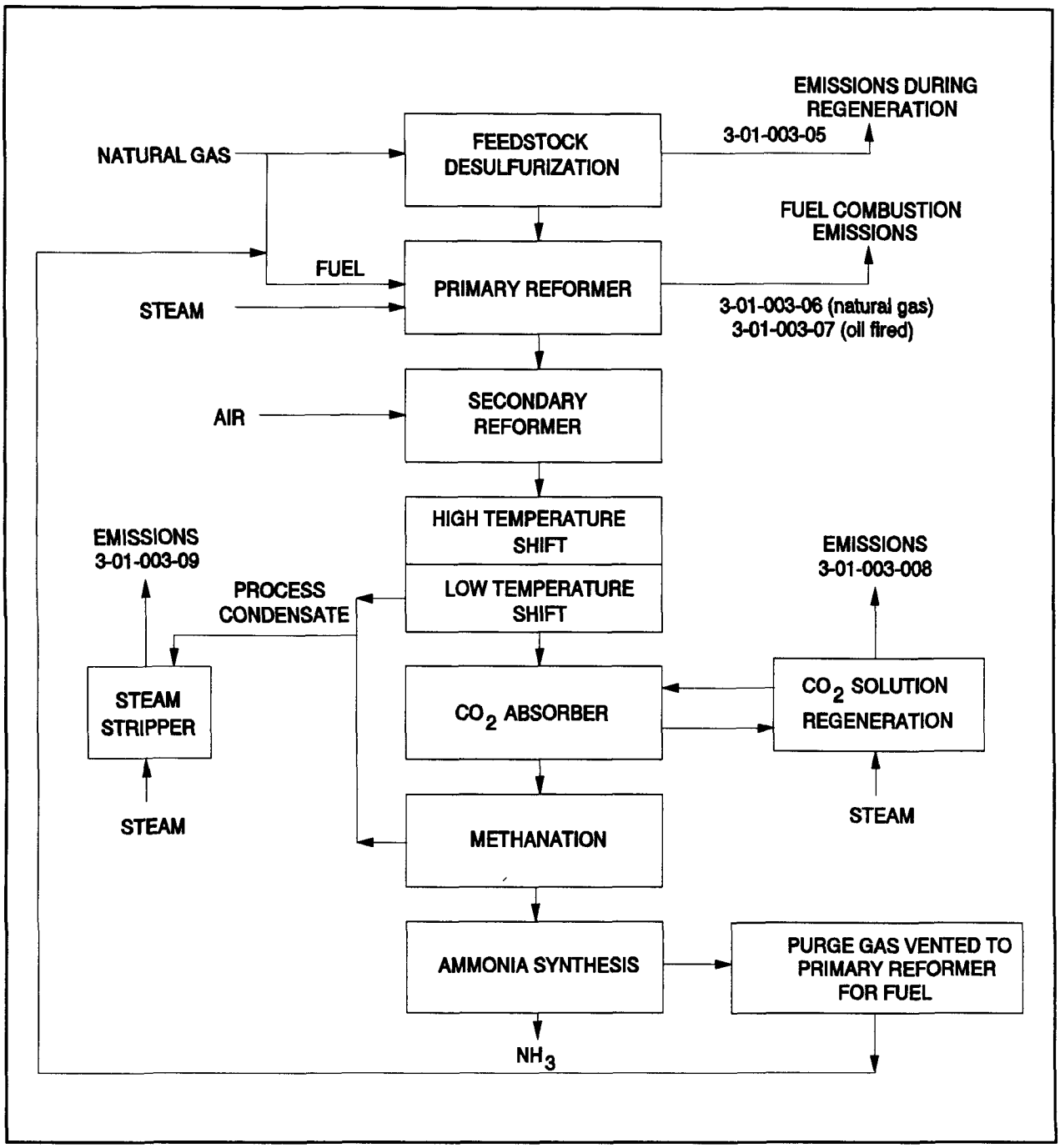


Figure 5.2-1 General flow diagram of a typical ammonia plant.

molecular weight hydrocarbons are not removed. Therefore, the heating value of the natural gas is not reduced.

5.2.2.2 Catalytic steam reforming

Natural gas leaving the desulfurization tank is mixed with process steam and preheated to 540°C (1004°F). The mixture of steam and gas enters the primary reformer (natural gas fired primary reformer and oil fired primary reformer tubes, which are filled with a nickel-based reforming

catalyst. Approximately 70 percent of the methane (CH_4) is converted to hydrogen and carbon dioxide (CO_2). An additional amount of CH_4 is converted to CO. This process gas is then sent to the secondary reformer, where it is mixed with compressed air that has been preheated to about 540°C (1004°F). Sufficient air is added to produce a final synthesis gas having a hydrogen-to-nitrogen mole ratio of 3 to 1. The gas leaving the secondary reformer is then cooled to 360°C (680°F) in a waste heat boiler.

5.2.2.3 Carbon monoxide shift

After cooling, the secondary reformer effluent gas enters a high temperature CO shift converter which is filled with chromium oxide initiator and iron oxide catalyst. The following reaction takes place in the carbon monoxide converter:

$$CO + H_2O \rightarrow CO_2 + H_2 \quad (1)$$

The exit gas is then cooled in a heat exchanger. In some plants, the gas is passed through a bed of zinc oxide to remove any residual sulfur contaminants that would poison the low temperature shift catalyst. In other plants, excess low temperature shift catalyst is added to ensure that the unit will operate as expected. The low temperature shift converter is filled with a copper oxide/zinc oxide catalyst. Final shift gas from this converter is cooled from 210 to 110°C (410 to 230°F) and enters the bottom of the carbon dioxide absorption system. Unreacted steam is condensed and separated from the gas in a knockout drum. This condensed steam (process condensate) contains ammonium carbonate ($[(NH_4)_2\ CO_3 \bullet H_2O]$) from the high temperature shift converter, methanol (CH_3OH) from the low temperature shift converter, and small amounts of sodium, iron, copper, zinc, aluminum and calcium.

Process condensate is sent to the stripper to remove volatile gases such as ammonia, methanol, and carbon dioxide. Trace metals remaining in the process condensate are removed by the ion exchange unit.

5.2.2.4 Carbon dioxide removal

In this step, CO_2 in the final shift gas is removed. CO_2 removal can be done by using two methods: monoethanolamine ($C_2H_4NH_2OH$) scrubbing and hot potassium scrubbing. Approximately 80 percent of the ammonia plants use monoethanolamine (MEA) to aid in removing CO_2. The CO_2 gas is passed upward through an adsorption tower countercurrent to a 15 to 30 percent solution of MEA in water fortified with effective corrosion inhibitors. After absorbing the CO_2, the amine solution is preheated and regenerated (carbon dioxide regenerator) in a reactivating tower. This reacting tower removes CO_2 by steam stripping and then by heating. The CO_2 gas (98.5 percent CO_2) is either vented to the atmosphere or used for chemical feedstock in other parts of the plant complex. The regenerated MEA is pumped back to the absorber tower after being cooled in a heat exchanger and solution cooler.

5.2.2.5 Methanation

Residual CO_2 in the synthesis gas is removed by catalytic methanation which is conducted over a nickel catalyst at temperatures of 400 to 600°C (752 to 1112°F) and pressures up to 3,000 kPa (435 psia) according to the following reactions:

$$CO + 3H_2 \rightarrow CH_4 + H_2O \quad (2)$$

$$CO_2 + H_2 \rightarrow CO + H_2O \quad (3)$$

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \quad (4)$$

Exit gas from the methanator, which has a 3:1 mole ratio of hydrogen and nitrogen, is then cooled to 38°C (100°F).

5.2.2.6 Ammonia Synthesis

In the synthesis step, the synthesis gas from the methanator is compressed at pressures ranging from 13,800 to 34,500 kPa (2000 to 5000 psia), mixed with recycled synthesis gas, and cooled to 0°C (32°F). Condensed ammonia is separated from the unconverted synthesis gas in a liquid-vapor separator and sent to a let-down separator. The unconverted synthesis is compressed and preheated to 180°C (356°F) before entering the synthesis converter which contains iron oxide catalyst. Ammonia from the exit gas is condensed and separated, then sent to the let-down separator. A small portion of the overhead gas is purged to prevent the buildup of inert gases such as argon in the circulating gas system.

Ammonia in the let-down separator is flashed to 100 kPa (14.5 psia) at -33°C (-27°F) to remove impurities from the liquid. The flash vapor is condensed in the let-down chiller where anhydrous ammonia is drawn off and stored at low temperature.

5.2.3 Emissions And Controls[1,3]

Pollutants from the manufacture of synthetic anhydrous ammonia are emitted from four process steps: 1) regeneration of the desulfurization bed, 2) heating of the catalytic steam, 3) regeneration of carbon dioxide scrubbing solution, and 4) steam stripping of process condensate.

More than 95 percent of the ammonia plants in the U. S. use activated carbon fortified with metallic oxide additives for feedstock desulfurization. The desulfurization bed must be regenerated about once every 30 days for an average period of 8 to 10 hours. Vented regeneration steam contains sulfur oxides (SO_x) and hydrogen sulfide (H_2S), depending on the amount of oxygen in the steam. Regeneration also emits hydrocarbons and carbon monoxide (CO). The reformer, heated with natural gas or fuel oil, emits combustion products such as NO_x, CO, SO_x, hydrocarbons, and particulates.

Carbon dioxide (CO_2) is removed from the synthesis gas by scrubbing with MEA or hot potassium carbonate solution. Regeneration of this CO_2 scrubbing solution with steam produces emission of water, NH_3, CO, CO_2 and monoethanolamine.

Cooling the synthesis gas after low temperature shift conversion forms a condensate containing NH_3, CO_2, methanol (CH_3OH), and trace metals. Condensate steam strippers are used to remove NH_3 and methanol from the water, and steam from this is vented to the atmosphere, emitting NH_3, CO_2, and methanol.

Some processes have been modified to reduce emissions and to improve utility of raw materials and energy. One such technique is the injection of the overheads into the reformer stack along with the combustion gases to eliminate emissions from the condensate steam stripper.

Table 5.2-1 (Metric and English Units).
UNCONTROLLED EMISSION FACTORS FOR A TYPICAL AMMONIA PLANT[a]

Emission Point (SCC)	CO			SO_2			Total Organic Compounds			Ammonia			CO_2		
	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating	kg/Mg	lb/ton	Emission Factor Rating
Desulfurization unit regeneration[b] (SCC 3-01-003-05)	6.9	13.8	E	0.0288[c,d]	0.0576[c,d]	E	3.6	7.2	E						
Carbon dioxide regenerator (SCC 3-01-003-008)	1.0[h]	2.0[h]	E				0.52[e]	1.04	E	1.0	2.0	E	1220	2440	E
Condensate steam stripper (SCC 3-01-003-09							0.6[f]	1.2	E	1.1	2.2	E	3.4[g]	6.8[g]	E

[a]References 1, 3. SCC = Source Classification Code
[b]Intermittent emissions. Desulfurization tank is regenerated for a 10-hour period on average once every 30 days.
[c]Assumed worst case, that all sulfur entering tank is emitted during regeneration.
[d]Normalized to a 24-hour emission factor. Total sulfur is 0.0096 kg/Mg (0.019 lb/ton).
[e]0.05 kg/Mg (0.1 lb/ton) is monoethanolamine.
[f]Mostly methanol, which is classified as Non Methane Organic Compound and a hazardous air pollutant (HAP).
[g]±60 %.
[h]Mostly CO.

References for Section 5.2

1. *Source Category Survey: Ammonia Manufacturing Industry*, EPA-450/3-80-014, U.S. Environmental Protection Agency, Research Triangle Park, NC, August 1980.

2. *North American Fertilizer Capacity Data*, Tennessee Valley Authority, Muscle Shoals, AL, December 1991.

3. G.D. Rawlings and R.B. Reznik, *Source Assessment: Synthetic Ammonia Production*, EPA-600/2-77-107m, U. S. Environmental Protection Agency, Research Triangle Park, NC, November 1977.

4. *AIRS Facility Subsystem Source Classification Codes and Emission Factor Listing For Criteria Pollutants*. EPA-450/4-90-003, U. S. Environmental Protection Agency, Research Triangle Park, NC 27711, March 1990.

5.5 CHLOR-ALKALI

5.5.1 General[1-2]

The chlor-alkali electrolysis process is used in the manufacture of chlorine, hydrogen and sodium hydroxide (caustic) solution. Of these three, the primary product is chlorine.

Chlorine is one of the more abundant chemicals produced by industry and has a wide variety of industrial uses. Chlorine was first used to produce bleaching agents for the textile and paper industries and for general cleaning and disinfecting. Since 1950, chlorine has become increasingly important as a raw material for synthetic organic chemistry. Chlorine is an essential component of construction materials, solvents, and insecticides. Annual production from U. S. facilities was 9.9 million megagrams (10.9 million tons) in 1990 after peaking at 10.4 million megagrams (11.4 million tons) in 1989.

5.5.2 Process Description[1-3]

There are three types of electrolytic processes used in the production of chlorine: 1) the diaphragm cell process, 2) the mercury cell process, and 3) the membrane cell process. In each process, a salt solution is electrolyzed by the action of direct electric current which converts chloride ions to elemental chlorine. The overall process reaction is:

$$2NaCl + 2H_2O \rightarrow Cl_2 + H_2 + 2NaOH \quad (1)$$

In all three methods the chlorine (Cl_2) is produced at the positive electrode (anode) and the caustic soda (NaOH) and hydrogen (H_2) are produced, directly or indirectly, at the negative electrode (cathode). The three processes differ in the method by which the anode products are kept separate from the cathode products.

Of the chlorine produced in the U. S. in 1989, 94 percent was produced either by the diaphragm cell or mercury cell process. Therefore, these will be the only two processes discussed in this section.

5.5.2.1 Diaphragm Cell

Figure 5.5-1 shows a simplified block diagram of the diaphragm cell process. Water and sodium chloride (NaCl) are combined to create the starting brine solution. The brine undergoes precipitation and filtration to remove impurities. Heat is applied and more salt is added. Then the nearly saturated, purified brine is heated again before direct electric current is applied. The anode is separated from the cathode by a permeable asbestos-based diaphragm to prevent the caustic soda from reacting with the chlorine. The chlorine produced at the anode is removed, and the saturated brine flows through the diaphragm to the cathode chamber. The chlorine is then purified by liquefaction and evaporation to yield a pure liquified product.

The caustic brine produced at the cathode is separated from salt and concentrated in an elaborate evaporative process to produce commercial caustic soda. The salt is recycled to saturate the dilute brine. The hydrogen removed in the cathode chamber is cooled and purified by removal of

oxygen, then used in other plant processes or sold.

5.5.2.2 Mercury Cell

Figure 5.5-2 shows a simplified block diagram for the mercury cell process. The recycled brine from the electrolysis process (anolyte) is dechlorinated and purified by a precipitation-filtration process. The liquid mercury cathode and the brine enter the cell flowing concurrently. The electrolysis process creates chlorine at the anode and elemental sodium at the cathode. The chlorine is removed from the anode, cooled, dried, and compressed. The sodium combines with mercury to form a sodium amalgam. The amalgam is further reacted with water in a separate reactor called the decomposer to produce hydrogen gas and caustic soda solution. The caustic and hydrogen are then separately cooled and the mercury removed before proceeding to storage, sales or other processes.

5.5.3 Emissions And Controls[4]

Table 5.5-1 is a summary of chlorine emission factors for chlor-alkali plants. Emissions from diaphragm and mercury cell plants include chlorine gas, carbon dioxide (CO_2), carbon monoxide (CO), and hydrogen. Gaseous chlorine is present in the blow gas from liquefaction, from vents in tank cars and tank containers during loading and unloading, and from storage tanks and process transfer tanks. Carbon dioxide emissions result from the decomposition of carbonates in the brine feed when contacted with acid. Carbon monoxide and hydrogen are created by side reactions within the production cell. Other emissions include mercury vapor from mercury cathode cells and chlorine from compressor seals, header seals, and the air blowing of depleted brine in mercury-cell plants. Emissions from these locations are, for the most part, controlled through the use of the gas in other parts of the plant, neutralization in alkaline scrubbers, or recovery of the chlorine from effluent gas streams.

Table 5.5-2 presents mercury emission factors based on two source tests used to substantiate the mercury national emission standard for hazardous air pollutants (NESHAP). Due to insufficient data, emission factors for CO, CO_2, and hydrogen are not presented here.

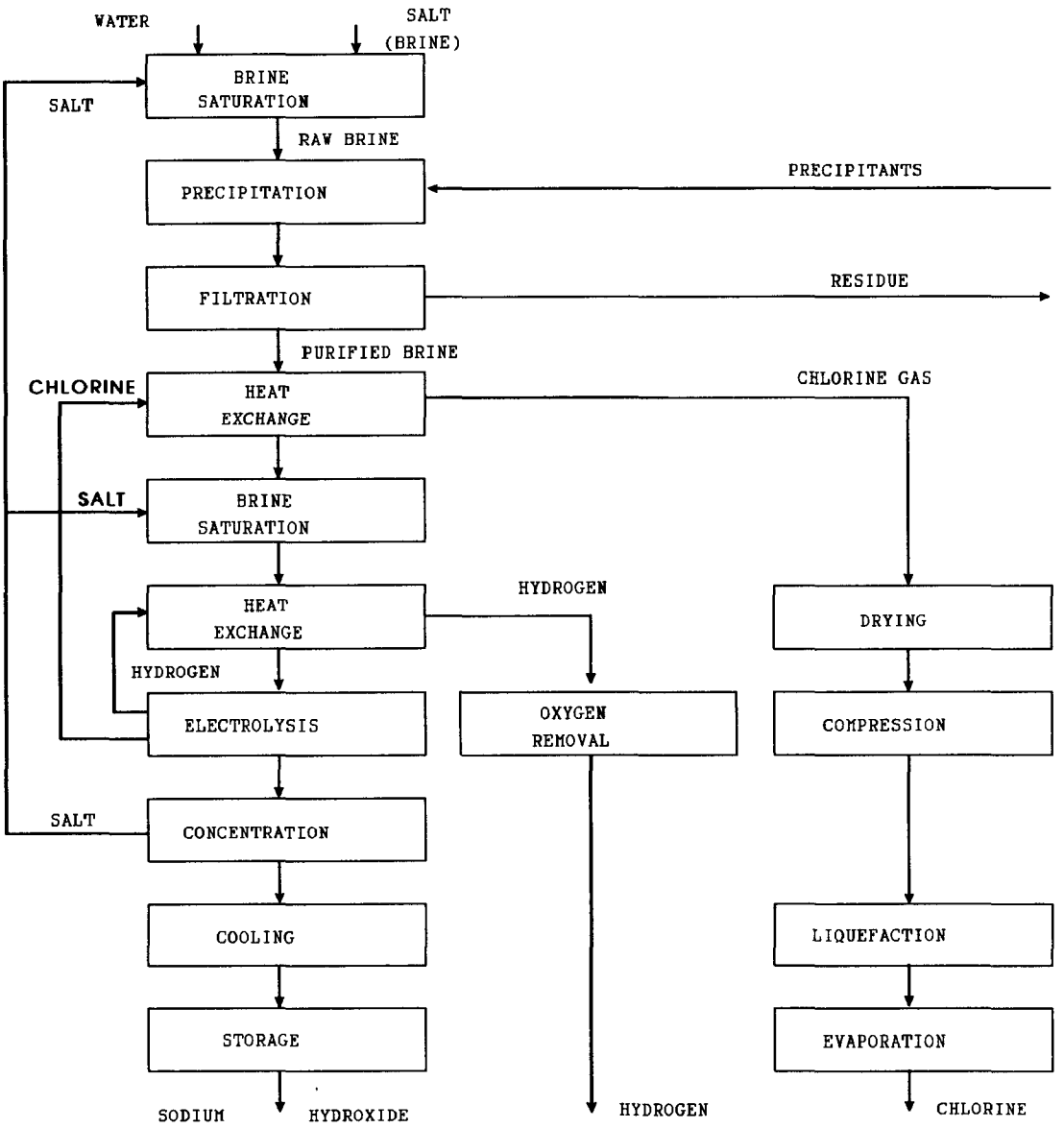


Figure 5.5-1 Simplified diagram of the diaphragm cell process

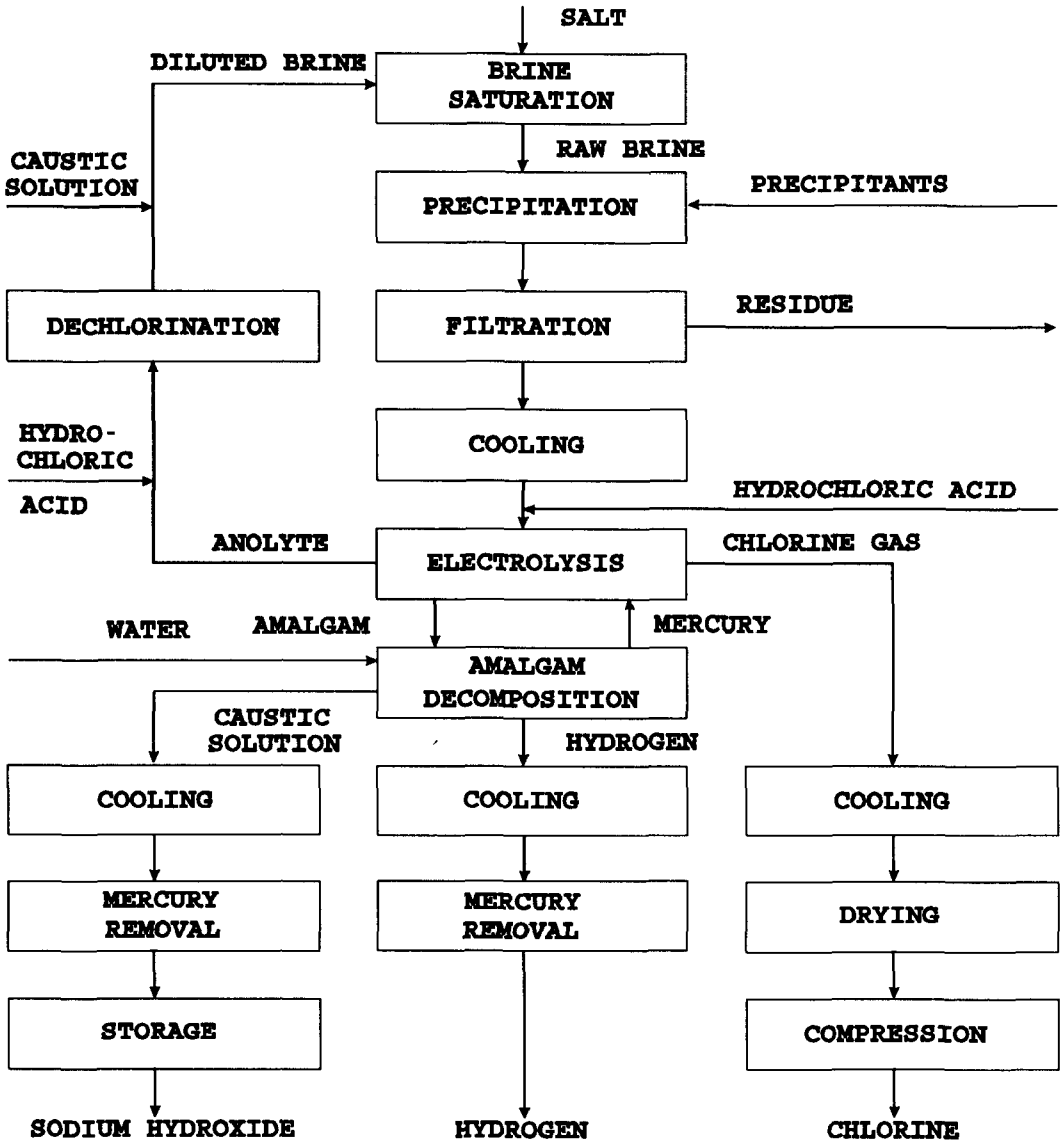


Figure 5.5-2 Simplified diagram of the mercury cell process

Table 5.5-1 (Metric Units).
EMISSION FACTORS FOR CHLORINE FROM CHLOR-ALKALI PLANTS[a]

Source (SCC)	Chlorine Gas	
	kg/Mg of Chlorine Produced	Emission Factor Rating
Liquefaction blow gases		
Diaphragm cell (SCC 3-01-008-01)	10 to 50	E
Mercury cell (SCC 3-01-008-02)	20 to 80	E
Water absorber[b] (SCC 3-01-008-99)	0.830	E
Caustic scrubber[b] (SCC 3-01-008-99)	0.006	E
Chlorine Loading		
Returned tank car vents (SCC 3-01-008-03)	4.1	E
Shipping container vents (SCC 3-01-008-04)	8.7	E
Mercury Cell Brine Air Blowing (SCC 3-01-008-05)	2.7	E

[a]Reference 4. SCC = Source Classification Code.
[b]Control devices.

Table 5.5-1 (English Units).
EMISSION FACTORS FOR CHLORINE FROM CHLOR-ALKALI PLANTS[a]

Source (SCC)	Chlorine Gas	
	kg/Mg of Chlorine Produced	Emission Factor Rating
Liquefaction blow gases		
Diaphragm cell (SCC 3-01-008-01)	20 to 100	E
Mercury cell (SCC 3-01-008-02)	40 to 160	E
Water absorber[b] (SCC 3-01-008-99)	1.66	E
Caustic scrubber[b] (SCC 3-01-008-99)	0.012	E
Chlorine Loading		
Returned tank car vents (SCC 3-01-008-03)	8.2	E
Shipping container vents (SCC 3-01-008-04)	17.3	E
Mercury Cell Brine Air Blowing (SCC 3-01-008-05)	5.4	E

[a]Reference 4. Units are lb of pollutant/ton .
[b]Control devices.

Table 5.5-2 (Metric and English Units).
EMISSION FACTORS FOR MERCURY FROM MERCURY CELL CHLOR-ALKALI PLANTS[a]

Type of Source (SCC)	Mercury Gas		
	kg/Mg of Clorine Produced	lb/ton of Clorine Produced	Emission Factor Rating
Hydrogen Vent (SCC 3-01-008-02)			
Uncontrolled	0.0017	0.0033	E
Controlled	0.0006	0.0012	E
End Box (SCC 3-01-008-02)	0.005	0.010	E

[a] SCC = Source Classification Code

References for Section 5.5

1. *Ullmann's Encyclopedia of Industrial Chemistry*, VCH Publishers, New York, 1989.

2. The Chlorine Institute, Inc., Washington, DC, January 1991.

3. *1991 Directory Of Chemical Producers*, Menlo Park, California: Chemical Information Services, Stanford Research Institute, Stanford, CA, 1991.

4. *Atmospheric Emissions from Chlor-Alkali Manufacture, AP-80*, U. S. EPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC, January 1971.

5. *B. F. Goodrich Chemical Company Chlor-Alkali Plant Source Tests, Calvert City, Kentucky*, EPA Contract No. CPA 70-132, Roy F. Weston, Inc., May 1972.

6. *Diamond Shamrock Corporation Chlor-Alkali Plant Source Tests, Delaware City, Delaware*, EPA Contract No. CPA 70-132, Roy F. Weston, Inc., June 1972.

5.7 Hydrochloric Acid

5.7.1 General[1]

Hydrochloric acid (HCl) is listed as a Title III Hazardous Air Pollutant (HAP). Hydrochloric acid is a versatile chemical used in a variety of chemical processes, including hydrometallurgical processing (e.g., production of alumina and/or titanium dioxide), chlorine dioxide synthesis, hydrogen production, activation of petroleum wells, and miscellaneous cleaning/etching operations including metal cleaning (e.g., steel pickling). Also known as muriatic acid, HCl is used by masons to clean finished brick work, is also a common ingredient in many reactions, and is the preferred acid for catalyzing organic processes. One example is a carbohydrate reaction promoted by hydrochloric acid, analogous to those in the digestive tracts of mammals.

Hydrochloric acid may be manufactured by several different processes, although over 90 percent of the HCl produced in the U.S. is a byproduct of the chlorination reaction. Currently, U.S. facilities produce approximately 2.3 million megagrams (2.5 million tons) of HCl annually, a slight decrease from the 2.5 million megagrams (2.8 million tons) produced in 1985.

5.7.2 Process Description[1-4]

Hydrochloric acid can be produced by one of the five following processes:

1) Synthesis from elements:

$$H_2 + Cl_2 \rightarrow 2HCl \quad (1)$$

2) Reaction of metallic chlorides, particularly sodium chloride (NaCl), with sulfuric acid (H_2SO_4) or a hydrogen sulfate:

$$NaCl + H_2SO_4 \rightarrow NaHSO_4 + HCl \quad (2)$$

$$NaCl + NaHSO_4 \rightarrow Na_2SO_4 + HCl \quad (3)$$

$$2NaCl + H_2SO_4 \rightarrow Na_2SO_4 + 2HCl \quad (4)$$

3) As a byproduct of chlorination, e.g. in the production of dichloromethane, trichloroethylene, perchloroethylene, or vinyl chloride:

$$C_2H_4 + Cl_2 \rightarrow C_2H_4Cl_2 \quad (5)$$

$$C_2H_4Cl_2 \rightarrow C_2H_3Cl + HCl \quad (6)$$

4) By thermal decomposition of the hydrated heavy-metal chlorides from spent pickle liquor in metal treatment:

$$2FeCl_3 + 6H_2O \rightarrow Fe_2O_3 + 3H_2O + 6HCl \quad (7)$$

5) From incineration of chlorinated organic waste:

$$C_4H_6Cl_2 + 5O_2 \rightarrow 4CO_2 + 2H_2O + 2HCl \quad (8)$$

Figure 5.7-1 is a simplified diagram of the steps used for the production of byproduct HCl from the chlorination process.

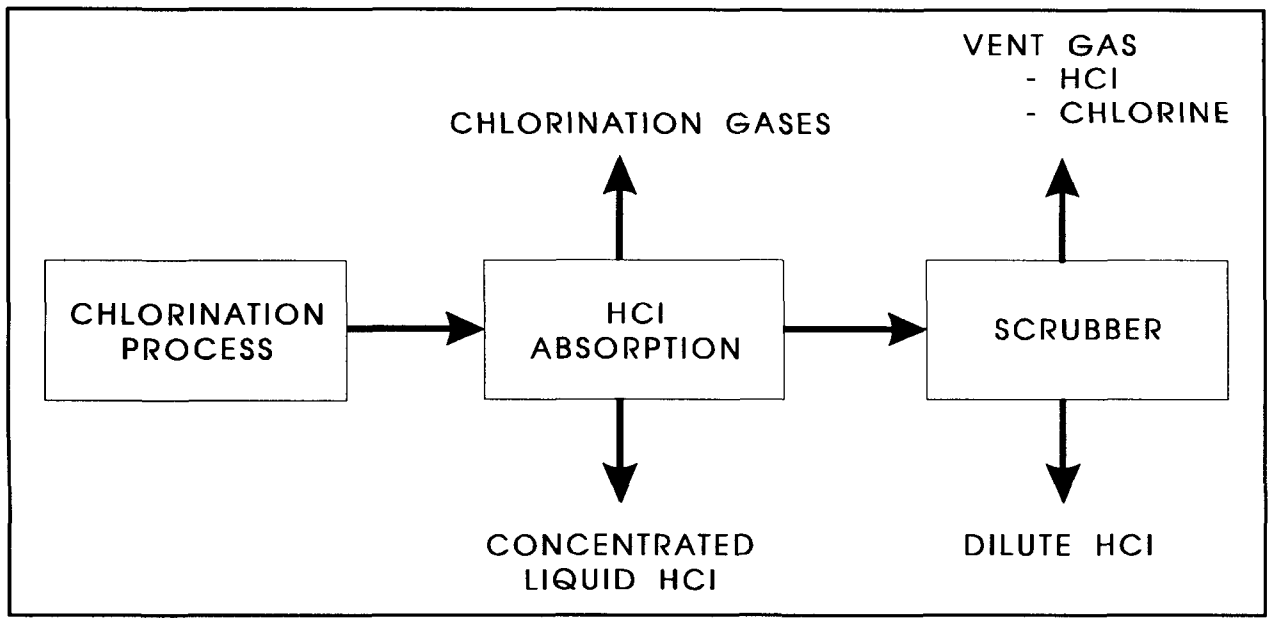


Figure 5.7-1 HCl production from chlorination process

After leaving the chlorination process, the HCl-containing gas stream proceeds to the absorption column, where concentrated liquid HCl is produced by absorption of HCl vapors into a weak solution of hydrochloric acid. The HCl-free chlorination gases are removed for further processing. The liquid acid is then either sold or used elsewhere in the plant. The final gas stream is sent to a scrubber to remove the remaining HCl prior to venting.

5.7.3 Emissions[4,5]

According to a 1985 emission inventory, over 89 percent of all HCl emitted to the atmosphere resulted from the combustion of coal. Less than one percent of the HCl emissions came from the direct production of HCl. Emissions from HCl production result primarily from gas exiting the HCl purification system. The contaminants are HCl gas, chlorine and chlorinated organic compounds. Emissions data are only available for HCl gas. Table 5.7-1 lists estimated emission factors for systems with and without final scrubbers.

TABLE 5.7-1 (METRIC UNITS)
EMISSION FACTORS FOR HYDROCHLORIC ACID MANUFACTURE[5]

Type of Process (SCC)	HCl Emissions	
	kg/Mg HCl Produced	Emission Factor Rating
Byproduct hydrochloric acid		
With final scrubber (3-011-01-99)	0.08	E
Without final scrubber (3-011-01-99)	0.90	E

TABLE 5.7-1 (ENGLISH UNITS)
EMISSION FACTORS FOR HYDROCHLORIC ACID MANUFACTURE[5]

Type of Process (SCC)	HCl Emissions	
	lb/ton HCl Produced	Emission Factor Rating
Byproduct hydrochloric acid		
With final scrubber (3-011-01-99)	0.15	E
Without final scrubber (3-011-01-99)	1.8	E

References for Section 5.7

1. *Encyclopedia of Chemical Technology, Third Edition*, Volume 12, John Wiley and Sons, New York, 1978.

2. *Ullmann's Encyclopedia of Industrial Chemistry*, Volume A, VCH Publishers, New York, 1989.

3. *Encyclopedia of Chemical Processing and Design*, Marcel Dekker, Inc., New York, 1987.

4. Hydrogen Chloride and Hydrogen Fluoride Emission Factors for the NAPAP (National Acid Precipitation Assessment Program) Emission Inventory, U.S. EPA, PB86-134040. October 1985.

5. *Atmospheric Emissions from Hydrochloric Acid Manufacturing Processes*. U.S. DHEW, PHS, CPEHS, National Air Polluting Control Administration. Durham, N.C. Publication Number AP-54. September 1969.

5.8 HYDROFLUORIC ACID

5.8.1 General[5-6]

Hydrogen fluoride (HF) is listed as a Title III Hazardous Air Pollutant (HAP). Hydrogen fluoride is produced in two forms, as anhydrous hydrogen fluoride and as aqueous hydrofluoric acid. The predominate form manufactured is hydrogen fluoride, a colorless liquid or gas which fumes on contact with air and is water soluble.

Traditionally, hydrofluoric acid has been used to etch and polish glass. Currently, the largest use for HF is in aluminum production. Other HF uses include uranium processing, petroleum alkylation, and stainless steel pickling. Hydrofluoric acid is also used to produce fluorocarbons used in aerosol sprays and in refrigerants. Although fluorocarbons are heavily regulated due to environmental concerns, other applications for fluorocarbons include manufacturing of resins, solvents, stain removers, surfactants, and pharmaceuticals.

5.8.2 Process Description[1-3,6]

Hydrofluoric acid is manufactured by the reaction of acid-grade fluorspar (CaF_2) with sulfuric acid (H_2SO_4) as shown below:

$$CaF_2 + H_2SO_4 \rightarrow CaSO_4 + 2HF \quad (1)$$

A typical HF plant is shown schematically in Figure 5.8-1. The endothermic reaction requires 30 to 60 minutes in horizontal rotary kilns externally heated to 200 to 250°C (390 to 480°F). Dry fluorspar ("spar") and a slight excess of sulfuric acid are fed continuously to the front end of a stationary prereactor or directly to the kiln by a screw conveyor. The prereactor mixes the components prior to charging to the rotary kiln. Calcium sulfate ($CaSO_4$) is removed through an air lock at the opposite end of the kiln. The gaseous reaction products—hydrogen fluoride and excess H_2SO_4 from the primary reaction, silicon tetrafluoride (SiF_4), sulfur dioxide (SO_2), carbon dioxide (CO_2), and water produced in secondary reactions—are removed from the front end of the kiln along with entrained particulate. The particulates are removed from the gas stream by a dust separator and returned to the kiln. Sulfuric acid and water are removed by a precondenser. Hydrogen fluoride vapors are then condensed in refrigerant condensers forming "crude HF", which is removed to intermediate storage tanks. The remaining gas stream passes through a sulfuric acid absorption tower or acid scrubber, removing most of the remaining hydrogen fluoride and some residual sulfuric acid, which are also placed in intermediate storage. The gases exiting the scrubber then pass through water scrubbers, where the SiF_4 and remaining HF are recovered as fluosilicic acid (H_2SiF_6). The water scrubber tailgases are passed through a caustic scrubber before being released to the atmosphere. The hydrogen fluoride and sulfuric acid are delivered from intermediate storage tanks to distillation columns, where the hydrofluoric acid is extracted at 99.98 percent purity. Weaker concentrations (typically 70 to 80 percent) are prepared by dilution with water.

5.8.3 Emissions And Controls[1-2,4]

Emission factors for various HF process operations are shown in Table 5.8-1. Emissions are suppressed to a great extent by the condensing, scrubbing, and absorption equipment used in the recovery and purification of the hydrofluoric and fluosilicic acid products. Particulate in the gas

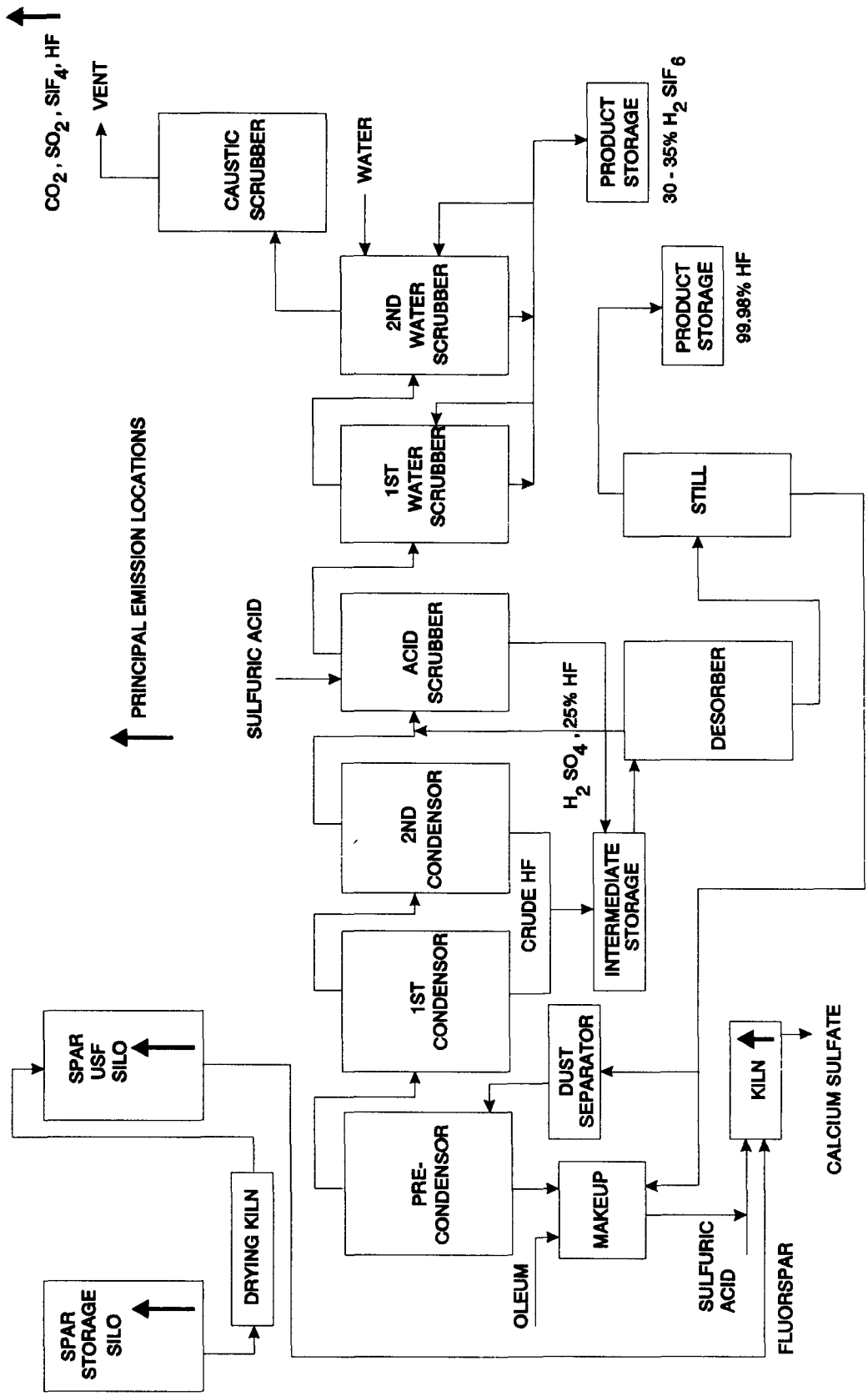


Figure 5.8-1. Hydrofluoric acid process flow diagram.

stream is controlled by a dust separator near the outlet of the kiln and is recycled to the kiln for further processing. The precondenser removes water vapor and sulfuric acid mist, and the condensers, acid scrubber and water scrubbers remove all but small amounts of HF, SiF_4, SO_2, and CO_2 from the tailgas. A caustic scrubber is employed to further reduce the levels of these pollutants in the tailgas.

Particulates are emitted during handling and drying of the fluorspar. They are controlled with bag filters at the spar silos and drying kilns. Fugitive dust emissions from spar handling and storage are controlled with flexible coverings and chemical additives.

Hydrogen fluoride emissions are minimized by maintaining a slight negative pressure in the kiln during normal operations. Under upset conditions, a standby caustic scrubber or a bypass to the tail caustic scrubber are used to control HF emissions from the kiln.

Table 5.8-1 (Metric Units).
EMISSION FACTORS FOR HYDROFLUORIC ACID MANUFACTURE[a]

Operation And Controls	Control efficiency (%)	Emissions: Gases: kg/Mg Acid Produced	Emissions: Gases: Emission Factor Rating	Emissions: Particulate (Spar): kg/Mg Fluorspar Produced	Emissions: Particulate (Spar): Emission Factor Rating
Spar Drying[b] (SCC 3-01-012-03)					
Uncontrolled	0			37.5	E
Fabric filter	99			0.4	E
Spar Handling Silos[c] (SCC 3-01-012-04)					
Uncontrolled	0			30.0	E
Fabric filter	99			0.3	E
Transfer Operations (SCC 3-01-012-05)					
Uncontrolled	0			3.0	E
Covers, additives	80			0.6	E
Tail Gas[c] (SCC 3-01-012-06)					
Uncontrolled	0	12.5 (HF) 15.0 (SiF_4) 22.5 (SO_2)	E E E		
Caustic Scrubber	99	0.1 (HF) 0.2 (SiF_4) 0.3 (SO_2)	E E E		

[a]SCC = Source Classification Code.
[b]Reference 1. Averaged from information provided by 4 plants. Hourly fluorspar input calculated from reported 1975 year capacity, assuming stoichiometric amount of calcium fluoride and 97.5% content in fluorspar. Hourly emission rates calculated from reported baghouse controlled rates. Values averaged are as follows:

Plant	1975 Capacity	Emissions fluorspar (kg/Mg)
1	13,600 Mg HF	53
2	18,100 Mg HF	65
3	45,400 Mg HF	21
4	10,000 Mg HF	15

[c]Reference 1. Four plants averaged for silo emissions, 2 plants for transfer operations emissions.
[d]Three plants averaged from Reference 1. Hydrogen fluoride and SiF_4 factors from Reference 4.

Table 5.8-1 (*English Units*).
EMISSION FACTORS FOR HYDROFLUORIC ACID MANUFACTURE[a]

Operation And Control	Control efficiency (%)	Emissions: Gases: lb/ton Acid Produced	Emissions: Gases: Emission Factor Rating	Emissions: Particulate (Spar): lb/ton Fluorspar Produced	Emissions: Particulate (Spar): Emission Factor Rating
Spar Drying[b] (SCC 3-01-012-03)					
Uncontrolled	0			75.0	E
Fabric filter	99			0.8	E
Spar handling silos[c] (SCC 3-01-012-04)					
Uncontrolled	0			60.0	E
Fabric Filter	99			0.6	E
Transfer operations (SCC 3-01-012-05)					
Uncontrolled	0			6.0	E
Covers, additives	80			1.2	E
Tail Gas[d] (SCC 3-01-012-06)					
Uncontrolled	0	25.0 (HF)	E		
		30.0 (SiF_4)	E		
		45.0 (SO_2)	E		
Caustic Scrubber	99	0.2 (HF)	E		
		0.3 (SiF_4)	E		
		0.5 (SO_2)	E		

[a]SCC = Source Classification Code

[b]Reference 1. Averaged from information provided by 4 plants. Hourly fluorspar input calculated from reported 1975 year capacity, assuming stoichiometric amount of calcium fluoride and 97.5% content in fluorspar. Hourly emission rates calculated from reported baghouse controlled rates. Values averaged are as follows:

Plant	1975 Capacity	Emissions fluorspar (lb/ton)
1	15,000 ton HF	106
2	20,000 ton HF	130
3	50,000 ton HF	42
4	11,000 ton HF	30

[c]Reference 1. Four plants averaged for silo emissions, 2 plants for transfer operations emissions.

[d]Three plants averaged from Reference 1. Hydrogen fluoride and SiF_4 factors from Reference 4.

References for Section 5.8

1. *Screening Study On Feasibility Of Standards Of Performance For Hydrofluoric Acid Manufacture*, EPA-450/3-78-109, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1978.

2. "Hydrofluoric Acid", *Kirk-Othmer Encyclopedia Of Chemical Technology*, Interscience Publishers, New York, NY, 1965.

3. W. R. Rogers and K. Muller, "Hydrofluoric Acid Manufacture", *Chemical Engineering Progress*, *59*(5): 85-8, May 1963.

4. J. M. Robinson, *et al.*, *Engineering And Cost Effectiveness Study Of Fluoride Emissions Control, Vol. 1*, PB 207 506, National Technical Information Service, Springfield, VA, 1972.

5. "Fluorine", *Encyclopedia Of Chemical Processing And Design*, Marcel Dekker, Inc., New York, NY, 1985.

6. "Fluorine Compounds, Inorganic", *Kirk-Othmer Encyclopedia Of Chemical Technology*, John Wiley & Sons, New York, NY, 1980.

5.9 NITRIC ACID

5.9.1 General[1-2]

In 1991, there were approximately 65 nitric acid (HNO_3) manufacturing plants in the U. S. with a total capacity of 10 million megagrams (11 million tons) of acid per year. The plants range in size from 5,400 to 635,000 megagrams (6,000 to 700,000 tons) per year. About 70 percent of the nitric acid produced is consumed as an intermediate in the manufacture of ammonium nitrate (NH_4NO_3), which in turn is used in fertilizers. The majority of the nitric acid plants are located in agricultural regions such as the Midwest, South Central, and Gulf States in order to accommodate the high concentration of fertilizer use. Another five to ten percent of the nitric acid produced is used for organic oxidation in adipic acid manufacturing. Nitric acid is also used in organic oxidation to manufacture terephthalic acid and other organic compounds. Explosive manufacturing utilizes nitric acid for organic nitrations. Nitric acid nitrations are used in producing nitrobenzene, dinitrotoluenes, and other chemical intermediates.[1] Other end uses of nitric acid are gold and silver separation, military munitions, steel and brass pickling, photoengraving, and acidulation of phosphate rock.

5.9.2 Process Description[1,3-4]

Nitric acid is produced by two methods. The first method utilizes oxidation, condensation, and absorption to produce a weak nitric acid. Weak nitric acid can have concentrations ranging from 30 to 70 percent nitric acid. The second method combines dehydrating, bleaching, condensing, and absorption to produce a high strength nitric acid from a weak nitric acid. High strength nitric acid generally contains more than 90 percent nitric acid. The following text provides more specific details for each of these processes.

5.9.2.1 Weak Nitric Acid Production[1,3-4]

Nearly all the nitric acid produced in the U.S. is manufactured by the high temperature catalytic oxidation of ammonia as shown schematically in Figure 5.9-1. This process typically consists of three steps: 1) ammonia oxidation, 2) nitric oxide oxidation, 3) absorption. Each step corresponds to a distinct chemical reaction.

Ammonia Oxidation - First, a 1:9 ammonia/air mixture is oxidized at a temperature of 750 to 800°C (1380 to 1470°F) as it passes through a catalytic convertor, according to the following reaction:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \quad (1)$$

The most commonly used catalyst is made of 90 percent platinum and 10 percent rhodium gauze constructed from squares of fine wire. Under these conditions the oxidation of ammonia to nitric oxide proceeds in an exothermic reaction with a range of 93 to 98 percent yield. Oxidation temperatures can vary from 750 to 900°C (1380 to 1650°F). Higher catalyst temperatures increase reaction selectivity toward nitric oxide (NO) production. Lower catalyst temperatures tend to be more selective toward less useful products; nitrogen (N_2) and nitrous oxide (N_2O). Nitric oxide is considered to be a criteria pollutant and nitrous

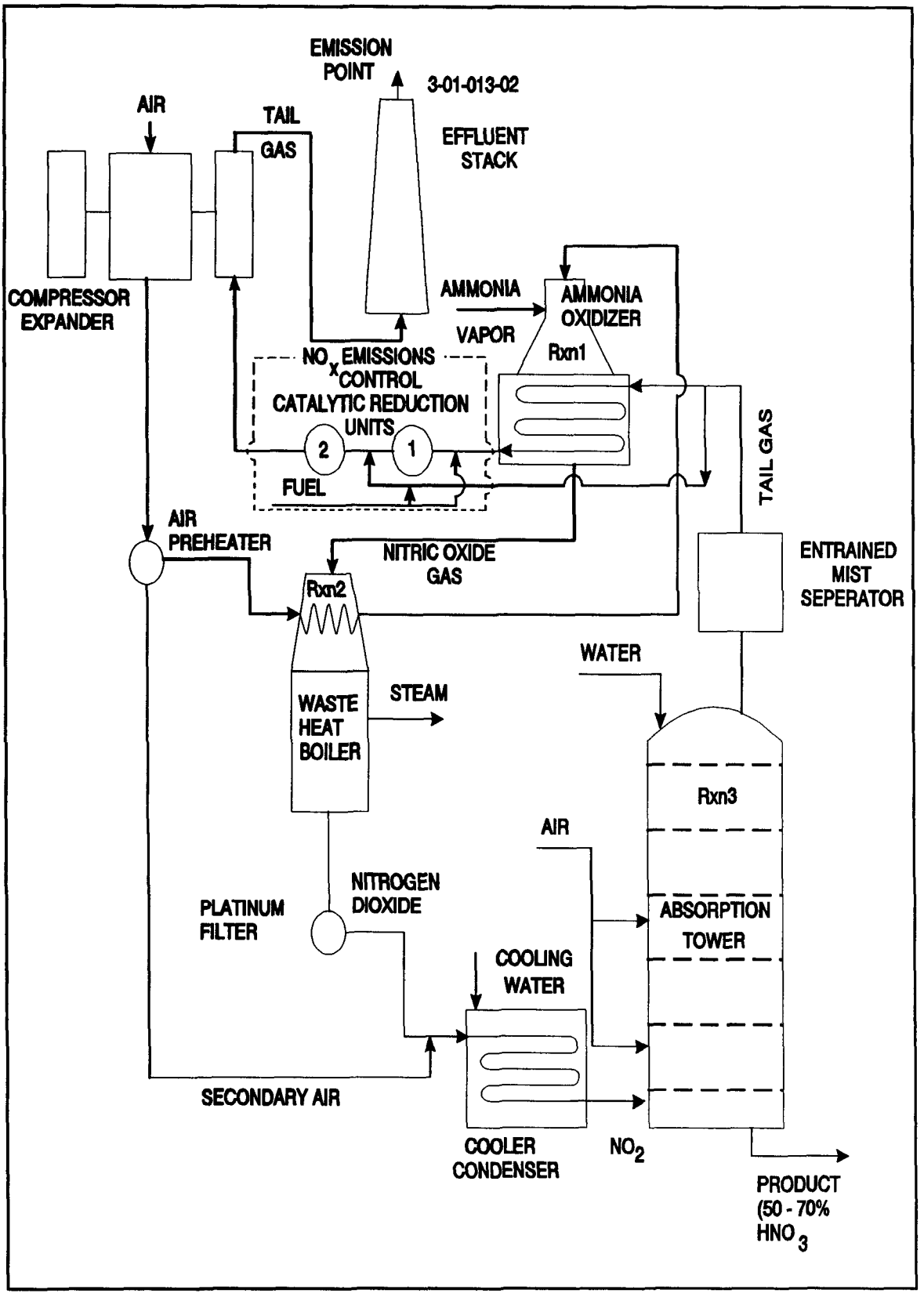


Figure 5.9-1. Flow diagram of typical nitric acid plant using single-pressure process (high-strength acid unit not shown).

oxide is known to be a global warming gas. The nitrogen dioxide/dimer mixture then passes through a waste heat boiler and a platinum filter.

Nitric Oxide Oxidation - The nitric oxide formed during the ammonia oxidation must be oxidized. The process stream is passed through a cooler/condenser and cooled to 38°C (100°F) or less at pressures up to 800 kPa (116 psia). The nitric oxide reacts noncatalytically with residual oxygen to form nitrogen dioxide and its liquid dimer, nitrogen tetroxide:

$$2NO + O_2 \rightarrow 2NO_2 \leftrightarrows N_2O_4 \quad (2)$$

This slow, homogeneous reaction is highly temperature and pressure dependent. Operating at low temperatures and high pressures promote maximum production of NO_2 within a minimum reaction time.

Absorption - The final step introduces the nitrogen dioxide/dimer mixture into an absorption process after being cooled. The mixture is pumped into the bottom of the absorption tower, while liquid dinitrogen tetroxide is added at a higher point. Deionized process water enters the top of the column. Both liquids flow countercurrent to the dioxide/dimer gas mixture. Oxidation takes place in the free space between the trays, while absorption occurs on the trays. The absorption trays are usually sieve or bubble cap trays. The exothermic reaction occurs as follows:

$$3NO_2 + H_2O \rightarrow 2HNO_3 + NO \quad (3)$$

A secondary air stream is introduced into the column to re-oxidize the NO which is formed in Reaction 3. This secondary air also removes NO_2 from the product acid. An aqueous solution of 55 to 65 percent (typically) nitric acid is withdrawn from the bottom of the tower. The acid concentration can vary from 30 to 70 percent nitric acid. The acid concentration depends upon the temperature, pressure, number of absorption stages, and concentration of nitrogen oxides entering the absorber.

There are two basic types of systems used to produce weak nitric acid: 1) single-stage pressure process, and 2) dual-stage pressure process. In the past, nitric acid plants have been operated at a single pressure, ranging from atmospheric pressure to 1400 kPa (14.7 to 203 psia). However, since Reaction 1 is favored by low pressures and Reactions 2 and 3 are favored by higher pressures, newer plants tend to operate a dual-stage pressure system, incorporating a compressor between the ammonia oxidizer and the condenser. The oxidation reaction is carried out at pressures from slightly negative to about 400 kPa (58 psia), and the absorption reactions are carried out at 800 to 1,400 kPa (116 to 203 psia).

In the dual-stage pressure system, the nitric acid formed in the absorber (bottoms) is usually sent to an external bleacher where air is used to remove (bleach) any dissolved oxides of nitrogen. The bleacher gases are then compressed and passed through the absorber. The absorber tail gas (distillate) is sent to an entrainment separator for acid mist removal. Next, the tail gas is reheated in the ammonia oxidation heat exchanger to approximately 200°C (392°F). The final step expands the gas in the power-recovery turbine. The thermal energy produced in this turbine can be used to drive the compressor.

5.9.2.2 High Strength Acid Nitric Production[1,3]

A high-strength nitric acid (98 to 99 percent concentration) can be obtained by concentrating the weak nitric acid (30 to 70 percent concentration) using extractive

distillation. The weak nitric acid cannot be concentrated by simple fractional distillation. The distillation must be carried out in the presence of a dehydrating agent. Concentrated sulfuric acid (typically 60 percent sulfuric acid) is most commonly used for this purpose. The nitric acid concentration process consists of feeding strong sulfuric acid and 55 to 65 percent nitric acid to the top of a packed dehydrating column at approximately atmospheric pressure. The acid mixture flows downward, countercurrent to ascending vapors. Concentrated nitric acid leaves the top of the column as 99 percent vapor, containing a small amount of NO_2 and O_2 resulting from dissociation of nitric acid. The concentrated acid vapor leaves the column and goes to a bleacher and a countercurrent condenser system to effect the condensation of strong nitric acid and the separation of oxygen and nitrogen oxide by-products. These byproducts then flow to an absorption column where the nitric oxide mixes with auxiliary air to form NO_2, which is recovered as weak nitric acid. Inert and unreacted gases are vented to the atmosphere from the top of the absorption column. Emissions from this process are relatively minor. A small absorber can be used to recover NO_2. Figure 5.9-2 presents a flow diagram of high-strength nitric acid production from weak nitric acid.

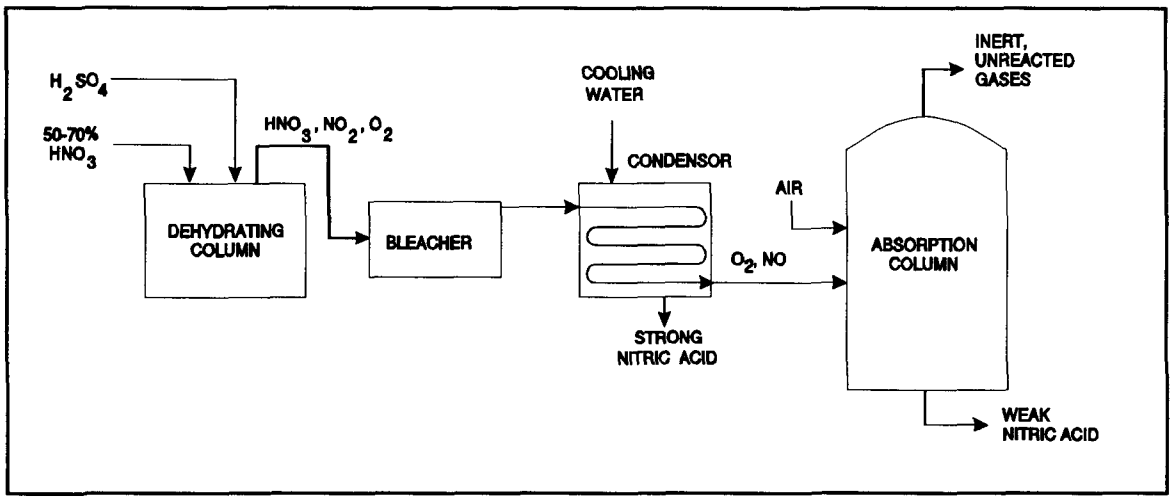


Figure 5.9-2. Flow diagram of high-strength nitric acid production from weak nitric acid.

5.9.3 Emissions And Controls[3-5]

Emissions from nitric acid manufacture consist primarily of NO, NO_2 (which account for visible emissions) and trace amounts of HNO_3 mist and NH_3. By far, the major source of nitrogen oxides is the tail gas from the acid absorption tower. In general, the quantity of NO_x emissions are directly related to the kinetics of the nitric acid formation reaction and absorption tower design. NO_x emissions can increase when there is (1) insuffficient air supply to the oxidizer and absorber, (2) low pressure, especially in the absorber, (3) high temperatures in the cooler-condenser and absorber, (4) production of an excessively high-strength product acid, (5) operation at high throughput rates, and (6) faulty equipment such as compressors or pumps which lead to lower pressures and leaks and decrease plant efficiency.

The two most common techniques used to control absorption tower tail gas emissions are extended absorption and catalytic reduction. Extended absorption reduces nitrogen oxide emissions by increasing the efficiency of the existing process absorption tower or incorporating an additional absorption tower. An efficiency increase is achieved by increasing

the number of absorber trays, operating the absorber at higher pressures, or cooling the weak acid liquid in the absorber. The existing tower can also be replaced with a single tower of a larger diameter and/or additional trays. See Reference 5 for the relevant equations.

In the catalytic reduction process (often termed catalytic oxidation or incineration), tail gases from the absorption tower are heated to ignition temperature, mixed with fuel (natural gas, hydrogen, propane, butane, naphtha, carbon monoxide, or ammonia) and passed over a catalyst bed. In the presence of the catalyst, the fuels are oxidized and the nitrogen oxides are reduced to N_2. The extent of reduction of NO_2 and NO to N_2 is a function of plant design, fuel type operating temperature and pressure, space velocity through the reduction catalytic reactor, type of catalyst and reactant concentration. Catalytic reduction can be used in conjunction with other NO_x emission controls. Other advantages include the capability to operate at any pressure and the option of heat recovery to provide energy for process compression as well as extra steam. Catalytic reduction can achieve greater NO_x reduction than extended absorption. However, high fuel costs have caused a decline in its use.

Two seldom used alternative control devices for absorber tail gas are molecular sieves and wet scrubbers. In the molecular sieve adsorption technique, tail gas is contacted with an active molecular sieve which catalytically oxidizes NO to NO_2 and selectively adsorbs the NO_2. The NO_2 is then thermally stripped from the molecular sieve and returned to the absorber. Molecular sieve adsorption has successfully controlled NO_x emissions in existing plants. However, many new plants do not install this method of control. Its implementation incurs high capital and energy costs. Molecular sieve adsorption is a cyclic system, whereas most new nitric acid plants are continuous systems. Sieve bed fouling can also cause problems.

Wet scrubbers use an aqueous solution of alkali hydroxides or carbonates, ammonia, urea, potassium permanganate, or caustic chemicals to "scrub" NO_x from the absorber tail gas. The NO and NO_2 are absorbed and recovered as nitrate or nitrate salts. When caustic chemicals are used, the wet scrubber is referred to as a caustic scrubber. Some of the caustic chemicals used are solutions of sodium hydroxide, sodium carbonate, or other strong bases that will absorb NO_x in the form of nitrate or nitrate salts. Although caustic scrubbing can be an effective control device, it is often not used due to its incurred high costs and the necessity to treat its spent scrubbing solution.

Comparatively small amounts of nitrogen oxides are also lost from acid concentrating plants. These losses (mostly NO_2) are from the condenser system, but the emissions are small enough to be controlled easily by inexpensive absorbers.

Acid mist emissions do not occur from the tail gas of a properly operated plant. The small amounts that may be present in the absorber exit gas streams are removed by a separator or collector prior to entering the catalytic reduction unit or expander.

The acid production system and storage tanks are the only significant sources of visible emissions at most nitric acid plants. Emissions from acid storage tanks may occur during tank filling.

Nitrogen oxide emission factors shown in Table 5.9-1 vary considerably with the type of control employed and with process conditions. For comparison purposes, the New Source Performance Standard on nitrogen emission expressed as NO_2 for both new and modified

plants is 1.5 kilograms of NO_2 emitted per megagram (3.0 lb/ton) of 100 percent nitric acid produced.

Table 5.9-1 (Metric and English Units).
NITROGEN OXIDE EMISSIONS FROM NITRIC ACID PLANTS[a]

Source	Control Efficiency %	NO_x		
		kg/Mg Nitric Acid Produced	lb/ton Nitric Acid Produced	Emission Factor Rating
Weak Acid Plant Tailgas				
Uncontrolled[b,c]	0	28	57	E
Catalytic reduction[c]				
Natural gas[d]	99.1	0.2	0.4	E
Hydrogen[e]	97-98.5	0.4	0.8	E
Natural gas/hydrogen (25%/75%)[f]	98-98.5	0.5	0.9	E
Extended absorption	95.8			
Single-Stage Process[g]		0.95	1.9	E
Dual-Stage Process[h]		1.1	2.1	E
Chilled Absorption and Caustic Scrubber[j]	N/A	1.1	2.2	E
High Strength Acid Plant[k]	N/A	5	10	E

[a] Assumes 100% acid. Production rates are in terms of total weight of product (water and acid). A plant producing 454 Mg (500 tons) per day of 55 weight % nitric acid is calculated as producing 250 Mg (275 tons)/day of 100% acid. NA = Not available.

[b] Reference 6. Based on a study of 12 plants, with average production rate of 207 Mg (100% HNO_3)/day (range 50 - 680) at average rated capacity of 97% (range 72 - 100%).

[c] Single-stage Pressure Process.

[d] Reference 4. Fuel is assumed to be natural gas. Based on data from 7 plants, with average production rate of 309 Mg (100% HNO_3)/day (range 50 - 977 Mg).

[e] Reference 6. Based on data from 2 plants, with average production rate of 145 Mg (100% HNO_3)/day (range 109 - 190 Mg) at average rated capacity of 98% (range 95 - 100%). Average absorber exit temperature is 29 °C (85 °F) {range 25 - 32°C (78 - 90°F)}, and the average exit pressure is 586 kPa (85 psig) {range 552 - 648 kPa (80 - 94 psig)}.

[f] Reference 6. Based on data from 2 plants, with average production rate of 208 Mg (100% HNO_3)/day (range 168 - 249 Mg) at average rated capacity of 110% (range 100 - 119%). Average absorber exit temperature is 33°C (91 °F) {range 28 - 37°C (83 - 98°F)}, and average exit pressure is 545 kPa (79 psig) {range 545 - 552 kPa (79 - 80 psig)}.

[g] Reference 4. Based on data from 5 plants, with average production rate of 492 Mg (100% HNO_3)/day (range 190 - 952 Mg).

[h] Reference 4. Based of data from 3 plants, with average production rate of 532 Mg (100% HNO_3)/day (range 286 - 850 Mg).

[j] Reference 4. Based of data from 1 plant, with a production rate of 628 Mg (100% HNO_3)/day.

[k] Reference 2. Based on data from 1 plant, with a production rate of 1.4 Mg (100% HNO_3)/hour at 100% rated capacity, of 98% nitric acid.

References for Section 5.9

1. *Alternative Control Techniques Document: Nitric And Adipic Acid Manufacturing Plants*, EPA-450/3-91-026, U. S. Environmental Protection Agency, OAQPS, Research Triangle Park, NC, December 1991.

2. *North American Fertilizer Capacity Data*, Tennessee Valley Authority, Muscle Shoals, AL, December 1991.

3. *Standards of Performance for Nitric Acid Plants*, 40 CFR 60 Subpart G.

4. Marvin Drabkin, *A Review Of Standards Of Performance For New Stationary Sources — Nitric Acid Plants*, EPA-450/3-79-013, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1979.

5. *Unit Operations Of Chemical Engineering*, 3rd Edition, McGraw-Hill, Inc. 1976.

6. *Atmospheric Emissions From Nitric Acid Manufacturing Processes*, 999-AP-27, U. S. Department of Health, Education, and Welfare, Cincinnati, OH, December 1966.

5.11 PHOSPHORIC ACID

5.11.1 General[1-2]

Phosphoric acid (H_3PO_4) is produced by two commercial methods: wet process and thermal process. Wet process phosphoric acid is used in fertilizer production. Thermal process phosphoric acid is of a much higher purity and is used in the manufacture of high grade chemicals, pharmaceutical, detergents, food products, beverages and other nonfertilizer products. In 1987 over 9 million megagrams (9 million tons) of wet process phosphoric acid was produced in the form of phosphorus pentoxide (P_2O_5). Only about 363,000 megagram (400,000 tons) of P_2O_5 was produced from the thermal process. Demand for phosphoric acid has increased approximately 2.3 to 2.5 percent per year.

The production of wet process phosphoric acid generates a considerable quantity of acidic cooling water with high concentrations of phosphorus and fluoride. This excess water is collected in cooling ponds which are used to temporarily store excess precipitation for subsequent evaporation and to allow recirculation of the process water to the plant for re-use. Leachate seeping is therefore a potential source of ground water contamination. Excess rainfall also results in water overflows from settling ponds. However, cooling water can be treated to an acceptable level of phosphorus and fluoride if discharge is necessary.

5.11.2 Process Description[3-5]

5.11.2.1 Wet Process Acid Production

In a wet process facility (see Figures 5.11-1A and 5.11-1B), phosphoric acid is produced by reacting sulfuric acid (H_2SO_4) with naturally occurring phosphate rock. The phosphate rock is dried, crushed and then continuously fed into the reactor along with sulfuric acid. The reaction combines calcium from the phosphate rock with sulfate, forming calcium sulfate ($CaSO_4$), commonly referred to as gypsum. Gypsum is separated from the reaction solution by filtration. Facilities in the U. S. generally use a dihydrate process that produces gypsum in the form of calcium sulfate with two molecules of water ($CaSO_4 \bullet 2\ H_2O$ or calcium sulfate dihydrate). Japanese facilities use a hemihydrate process which produces calcium sulfate with a half molecule of water ($CaSO_4 \bullet \frac{1}{2}\ H_2O$). This one-step hemihydrate process has the advantage of producing wet process phosphoric acid with a higher P_2O_5 concentration and less impurities than the dihydrate process. Due to these advantages, some U. S. companies have recently converted to the hemihydrate process. However, since most wet process phosphoric acid is still produced by the dihydrate process, the hemihydrate process will not be discussed in detail here. A simplified reaction for the dihydrate process is as follow:

$$Ca_3(PO_4)_2 + 3H_2SO_4 + 6H_2O \rightarrow 2H_3PO_4 + 3[CaSO_4 \bullet 2H_2O]\downarrow \quad (1)$$

In order to make the strongest phosphoric acid possible and to decrease evaporation costs, 93 percent sulfuric acid is normally used. Because the proper ratio of acid to rock in the reactor is critical, precise automatic process control equipment is employed in the regulation of these two feed streams.

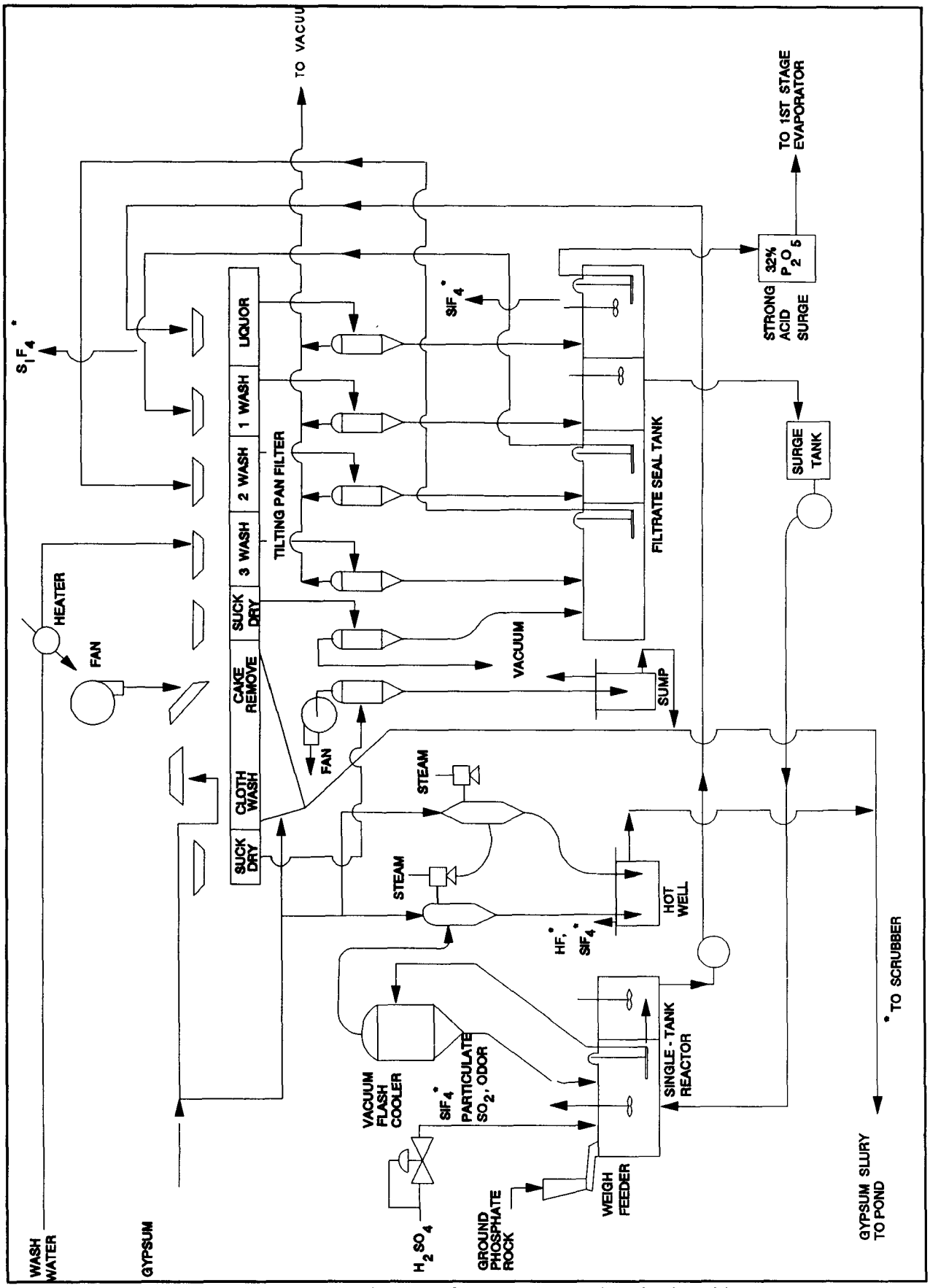


Figure 5.11-1A. Flow diagram of a wet process phosphoric acid plant.

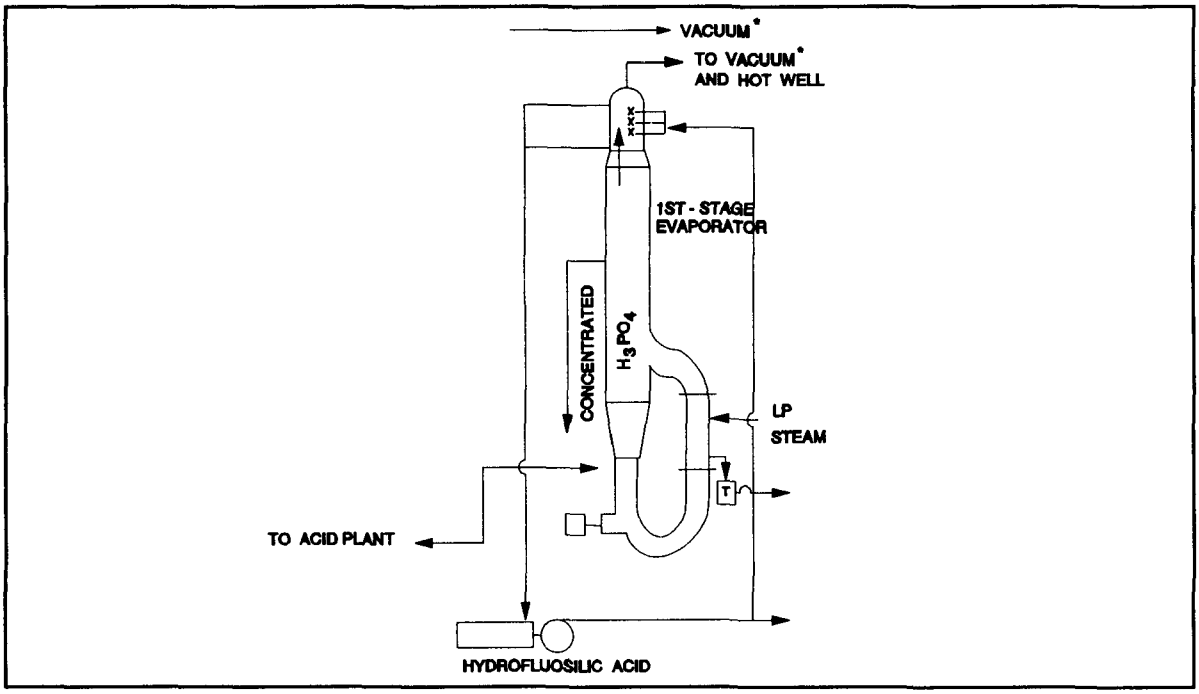


Figure 5.11-1B. Flow diagram of a wet process phosphoric acid plant (cont.).

During the reaction, gypsum crystals are precipitated and separated from the acid by filtration. The separated crystals must be washed thoroughly to yield at least a 99 percent recovery of the filtered phosphoric acid. After washing, the slurried gypsum is pumped into a gypsum pond for storage. Water is syphoned off and recycled through a surge cooling pond to the phosphoric acid process. Approximately 0.7 acres of cooling and settling pond area is required for every ton of daily P_2O_5 capacity.

Considerable heat is generated in the reactor. In older plants, this heat was removed by blowing air over the hot slurry surface. Modern plants vacuum flash cool a portion of the slurry, and then recycle it back into the reactor.

Wet process phosphoric acid normally contains 26 to 30 percent P_2O_5. In most cases, the acid must be further concentrated to meet phosphate feed material specifications for fertilizer production. Depending on the types of fertilizer to be produced, phosphoric acid is usually concentrated to 40 to 55 percent P_2O_5 by using two or three vacuum evaporators.

5.11.2.2 Thermal Process Acid Production

Raw materials for the production of phosphoric acid by the thermal process are elemental (yellow) phosphorus, air and water. Thermal process phosphoric acid manufacture, as shown schematically in Figure 5.11-2, involves three major steps: 1) combustion, 2) hydration, and 3) demisting.

In combustion, the liquid elemental phosphorus is burned (oxidized) in ambient air in a combustion chamber at temperatures of 1650 to 2760°C (3000 to 5000°F) to form phosphorus pentoxide (Reaction 2). The phosphorus pentoxide is then hydrated with dilute phosphoric acid (H_3PO_4) or water to produce strong phosphoric acid liquid (Reaction 3). Demisting, the final step, removes the phosphoric acid mist from the combustion gas stream before release to the atmosphere.

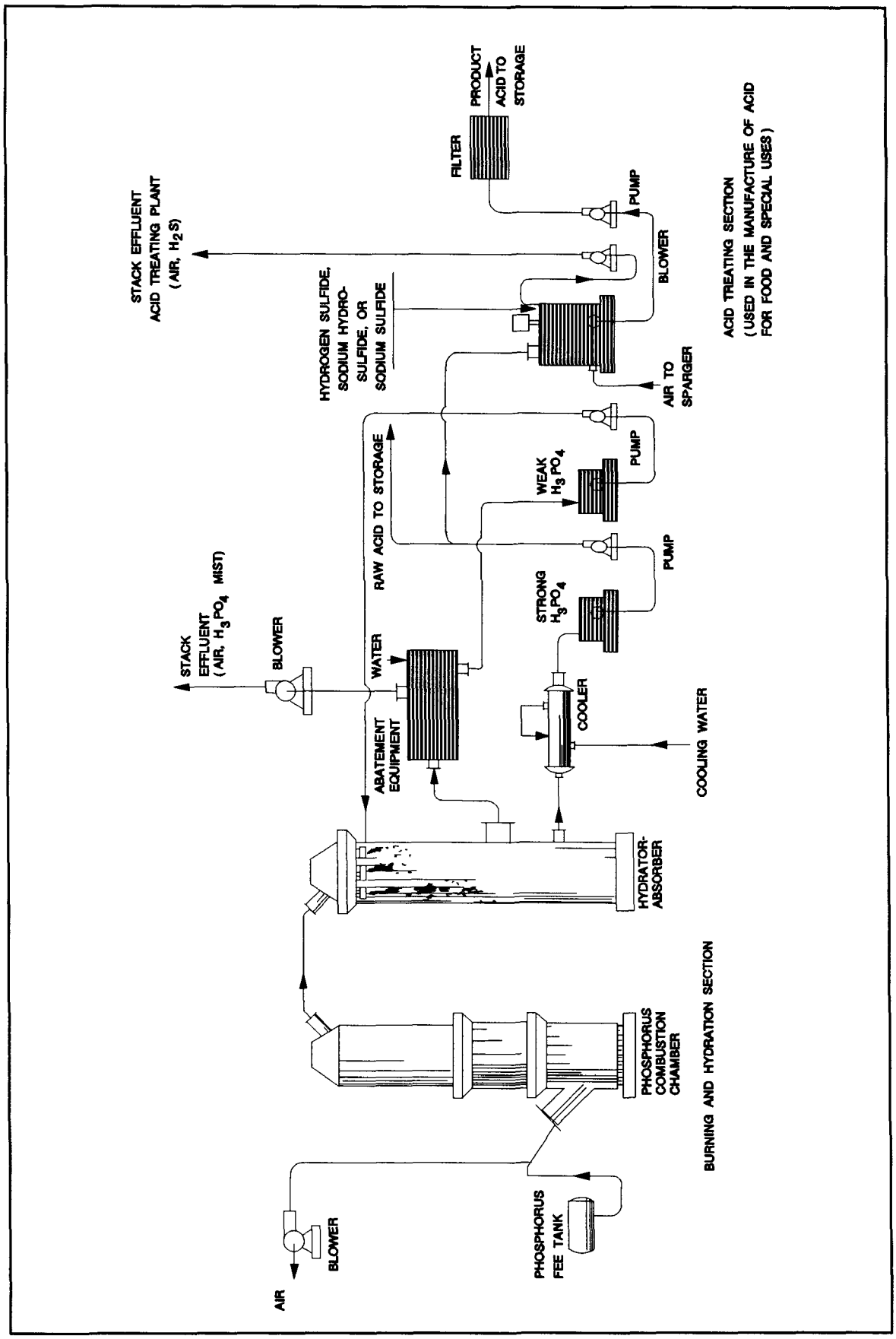


Figure 5.11-2. Flow diagram of a thermal process phosphoric acid plant.

This is usually done with high-pressure drop demistors.

$$P_4 + 5O_2 \rightarrow 2P_2O_5 \quad (2)$$

$$2P_2O_5 + 6H_2O \rightarrow 4H_3PO_4 \quad (3)$$

Concentration of phosphoric acid (H_3PO_4) produced from thermal process normally ranges from 75 to 85 percent. This high concentration is required for high grade chemical production and other nonfertilizer product manufacturing. Efficient plants recover about 99.9 percent of the elemental phosphorus burned as phosphoric acid.

5.11.3 Emissions And Controls [3-6]

Emission factors for controlled and uncontrolled wet phosphoric acid production are shown in Tables 5.11-1 and 5.11-2, respectively. Emission factors for controlled thermal phosphoric acid production are shown in Table 5.11-3.

5.11.3.1 Wet Process

Major emissions from wet process acid production includes gaseous fluorides, mostly silicon tetrafluoride (SiF_4) and hydrogen fluoride (HF). Phosphate rock contains 3.5 to 4.0 percent fluorine. In general, part of the fluorine from the rock is precipitated out with the gypsum, another part is leached out with the phosphoric acid product, and the remaining portion is vaporized in the reactor or evaporator. The relative quantities of fluorides in the filter acid and gypsum depend on the type of rock and the operating conditions. Final disposition of the volatilized fluorine depends on the design and operation of the plant.

Scrubbers may be used to control fluorine emissions. Scrubbing systems used in phosphoric acid plants include venturi, wet cyclonic and semi-cross flow scrubbers. The leachate portion of the fluorine may be deposited in settling ponds. If the pond water becomes saturated with fluorides, fluorine gas may be emitted to the atmosphere.

The reactor in which phosphate rock is reacted with sulfuric acid is the main source of emissions. Fluoride emissions accompany the air used to cool the reactor slurry. Vacuum flash cooling has replaced the air cooling method to a large extent, since emissions are minimized in the closed system.

Acid concentration by evaporation is another source of fluoride emissions. Approximately 20 to 40 percent of the fluorine originally present in the rock vaporizes in this operation.

Total particulate emissions from process equipment were measured for one digester and for one filter. As much as 5.5 kilograms of particulate per megagram (11 pounds per ton) of P_2O_5 were produced by the digester, and approximately 0.1 kilograms per megagram (.2 pounds per ton) of P_2O_5 were released by the filter. Of this particulate, three to six percent were fluorides.

Particulate emissions occurring from phosphate rock handling are discussed in Section 8.18, Phosphate Rock Processing.

5.11.3.2 Thermal Process

The major source of emissions from the thermal process is phosphoric acid mist (H_3PO_4) contained in the gas stream from the hydrator. The particle size of the acid mist ranges from 1.4 to 2.6 micrometers (μm). It is not uncommon for as much as half of the total phosphorus pentoxide (P_2O_5) to be present as liquid phosphoric acid particles suspended in the gas stream. Efficient plants are economically motivated to control this potential loss with various control equipment. Control equipment commonly used in thermal process phosphoric acid plants includes venturi scrubbers, cyclonic separators with wire mesh mist eliminators, fiber mist eliminators, high energy wire mesh contractors, and electrostatic precipitators.

Table 5.11-1. (Metric and English Units).
CONTROLLED EMISSION FACTORS FOR WET PHOSPHORIC ACID PRODUCTION[a]

Source (SCC Code)	Fluorine		
	kg/Mg P_2O_5 Produced	lb/ton P_2O_5 Produced	Emission Factor Rating
Reactor[b] (SCC 3-01-016-01)	1.9×10^{-3}	3.8×10^{-3}	A
Evaporator[c] (SCC 3-01-016-99)	0.022×10^{-3}	0.044×10^{-3}	B
Belt Filter[c] (SCC 3-01-016-99)	0.32×10^{-3}	0.64×10^{-3}	B
Belt Filter Vacuum Pump[c] (SCC 3-01-016-99)	0.073×10^{-3}	0.15×10^{-3}	B
Gypsum settling and cooling ponds[d,e] (SCC 3-01-016-02)	Site specific	Site specific	

[a] SCC = Source Classification Code
[b] Reference 8-13
[c] Reference 13
[d] Reference 18. Site specific. Acres of cooling pond required: ranges from 0.10 acre per daily ton P_2O_5 produced in the summer in the southeastern United States to zero in the colder locations in the winter months when the cooling ponds are frozen.
[e] Reference 19 states "Based on our findings concerning the emissions of fluoride from gypsum ponds, it was concluded than no investigator had as yet established experimentally the fluoride emission from gypsum ponds."

Table 5.11-2. (Metric and English Units).
UNCONTROLLED EMISSION FACTORS FOR WET PHOSPHORIC ACID PRODUCTION[a]

Source (SCC Code)	Nominal Percent Control Efficiency	Fluoride		
		kg/Mg P_2O_5 Produced	lb/ton P_2O_5 Produced	Emission Factor Rating
Reactor[b] (SCC 3-01-016-01)	99	0.19	0.38	B
Evaporator[c] (SCC 3-01-016-99)	99	0.00217	0.0044	C
Belt Filter[c] (SCC 3-01-016-99)	99	0.032	0.064	C
Belt Filter Vacuum Pump[c] (SCC 3-01-016-99)	99	0.0073	0.015	C
Gypsum settling and cooling ponds[d,e] (SCC 3-01-016-02)	N/A	Site specific	Site specific	

[a] SCC = Source Classification Code.
[b] Reference 8-13
[c] Reference 13
[d] Reference 18. Site specific. Acres of cooling pond required: ranges from 0.04 hectare per daily Mg (0.10 acre per daily ton) P_2O_5 produced in the summer in the southeastern U. S. to zero in the colder locations in the winter months when the cooling ponds are frozen.
[e] Reference 19 states "Based on our findings concerning the emissions of fluoride from gypsum ponds, it was concluded than no investigator had as yet established experimentally the fluoride emission from gypsum ponds."

Table 5.11-3. (Metric and English Units).
CONTROLLED EMISSION FACTORS FOR THERMAL PHOSPHORIC ACID PRODUCTION[a]

Source (SCC Code)	Nominal Percent Control Efficiency	Particulate[b]		
		kg/Mg P_2O_5 Produced	lb/ton P_2O_5 Produced	Emission Factor Rating
Packed tower (SCC 3-01-017-03)	95.5	1.07	2.14	E
Venturi scrubber (SCC3-01-017-04)	97.5	1.27	2.53	E
Glass fiber mist eliminator (SCC 3-01-017-05)	96-99.9	0.35	0.69	E
Wire mesh mist eliminator (SCC 3-01-017-06)	95	2.73	5.46	E
High pressure drop mist (SCC 3-01-017-07)	99.9	0.06	0.11	E
Electrostatic precipitator (3-01-017-08)	98-99	0.83	1.66	E

[a] SCC = Source Classification Code.
[b] Reference 6.

References for Section 5.11

1. "Phosphoric Acid", Chemical and Engineering News, March 2, 1987.

2. *Sulfuric/Phosphoric Acid Plant Operation*, American Institute Of Chemical Engineers, New York, 1982.

3. P. Becker, *Phosphates And Phosphoric Acid, Raw Materials, Technology, And Economics Of The Wet Process*, 2nd Edition, Marcel Dekker, Inc., New York, 1989.

4. *Atmospheric Emissions from Wet Process Phosphoric Acid Manufacture*, AP-57, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1970.

5. *Atmospheric Emissions From Thermal Process Phosphoric Acid Manufacture*, AP-48, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1968.

6. *Control Techniques For Fluoride Emissions*, Unpublished, U. S. Public Health Service, Research Triangle Park, NC, September 1970.

7. *Final Guideline Document: Control Of Fluoride Emissions From Existing Phosphate Fertilizer Plants*, EPA-450/2-77-005, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1977.

8. *Summary Of Emission Measurements - East Phos Acid*, International Minerals And Chemical Corporation, Polk County, FL, August 1990.

9. *Summary Of Emission Measurements - East Phos Acid*, International Minerals And Chemical Corporation, Polk County, FL, February 1991.

10. *Summary Of Emission Measurements - East Phos Acid*, International Minerals And Chemical Corporation, Polk County, FL, August 1991.

11. *Source Test Report*, Seminole Fertilizer Corporation, Bartow, FL, September 1990.

12. *Source Test Report*, Seminole Fertilizer Corporation, Bartow, FL, May 1991.

13. *Stationary Source Sampling Report, Texasgulf Chemicals Company, Aurora*, NC, Entropy Environmentalists, Inc., Research Triangle Park, NC, December 1987.

14. *Stationary Source Sampling Report, Texasgulf Chemicals Company, Aurora*, NC, Entropy Environmentalists, Inc., Research Triangle Park, NC. March 1987.

15. *Sulfur Dioxide Emissions Test. Phosphoric Acid Plant, Texasgulf Chemicals Company, Aurora, NC*, Entropy Environmentalists, Inc., Research Triangle Park, NC, August 1988.

16. *Stationary Source Sampling Report, Texasgulf Chemicals Company, Aurora, NC*, Entropy Environmentalists, Inc., Research Triangle Park, NC, August 1987.

17. *Source Test Report, FMC Corporation, Carteret, NJ*, Princeton Testing Laboratory, Princeton, NJ, March 1991.

18. A. J. Buonicore and W. T. Davis, eds., *Air Pollution Engineering Manual*, Van Nostrand Reinhold, New York, NY, 1992.

19. *Evaluation Of Emissions And Control Techniques For Reducing Fluoride Emission From Gypsum Ponds In The Phosphoric Acid Industry*, EPA-600/2-78-124, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1978.

5.15 SOAP AND DETERGENTS

5.15.1 General

5.15.1.1 Soap Manufacturing[1,3,6]

The term "soap" refers to a particular type of detergent in which the water-solubilized group is carboxylate and the positive ion is usually sodium or potassium. The largest soap market is bar soap used for personal bathing. Synthetic detergents replaced soap powders for home laundering in the late 1940s, because the carboxylate ions of the soap react with the calcium and magnesium ions in the natural hard water to form insoluble materials called lime soap. Some commercial laundries that have soft water continue to use soap powders. Metallic soaps are alkali-earth or heavy-metal long-chain carboxylates which are insoluble in water but soluble in nonaqueous solvents. They are used as additives in lubricating oils, greases, rust inhibitors, and jellied fuels.

5.15.1.2 Detergent Manufacturing[1,3,6,8]

The term "synthetic detergent products" applies broadly to cleaning and laundering compounds containing surface-active (surfactant) compounds along with other ingredients. Heavy-duty powders and liquids for home and commercial laundry detergent comprise 60 to 65 percent of the U. S. soap and detergent market and were estimated at 2.6 megagrams (2.86 million tons) in 1990.

Until the early 1970s, almost all laundry detergents sold in the U. S. were heavy-duty powders. Liquid detergents were introduced that utilized sodium citrate and sodium silicate. The liquids offered superior performance and solubility at a slightly increased cost. Heavy-duty liquids now account for 40 percent of the laundry detergents sold in the U. S., up from 15 percent in 1978. As a result, 50 percent of the spray drying facilities for laundry granule production have closed since 1970. Some current trends, including the introduction of superconcentrated powder detergents, will probably lead to an increase in spray drying operations at some facilities. Manufacturers are also developing more biodegradable surfactants from natural oils.

5.15.2 Process Descriptions

5.15.2.1 Soap [1,3,6]

From American colonial days to the early 1940s, soap was manufactured by an alkaline hydrolysis reaction called saponification. Soap was made in huge kettles into which fats, oils, and caustic soda were piped and heated to a brisk boil. After cooling for several days, salt was added, causing the mixture to separate into two layers with the "neat" soap on top and spent lye and water on the bottom. The soap was pumped to a closed mixing tank called a crutcher where builders, perfumes, and other ingredients were added. Builders are alkaline compounds which improve the cleaning performance of the soap. Finally, the soap was rolled into flakes, cast or milled into bars, or spray-dried into soap powder.

An important modern process (post 1940s) for making soap is the direct hydrolysis of fats by water at high temperatures. This permits fractionation of the fatty acids, which are neutralized to soap

in a continuous process as shown in Figure 5.15-1. Advantages for this process include close control of the soap concentration, the preparation of soaps of certain chain lengths for specific purposes, and easy recovery of glycerin, a byproduct. After the soap is recovered, it is pumped to the crutcher and treated the same as the product from the kettle process.

5.15.2.2 Detergent[1,3,6,8]

The manufacture of spray-dried detergent has three main processing steps: 1) slurry preparation, 2) spray drying and 3) granule handling. The three major components of detergent are surfactants (to remove dirt and other unwanted materials), builders (to treat the water to improve surfactant performance) and additives to improve cleaning performance. Additives may include bleaches, bleach activators, antistatic agents, fabric softeners, optical brighteners, antiredeposition agents, and fillers.

The formulation of slurry for detergent granules requires the intimate mixing of various liquid, powdered, and granulated materials. Detergent slurry is produced by blending liquid surfactant with powdered and liquid materials (builders and other additives) in a closed mixing tank called a soap crutcher. Premixing of various minor ingredients is performed in a variety of equipment prior to charging to the crutcher or final mixer. Figure 5.15-2 illustrates the various operations. Liquid surfactant used in making the detergent slurry is produced by the sulfonation of either a linear alkylate or a fatty acid, which is then neutralized with a caustic solution containing sodium hydroxide (NaOH). The blended slurry is held in a surge vessel for continuous pumping to a spray dryer. The slurry is atomized by spraying through nozzles rather than by centrifugal action. The slurry is sprayed at pressures of 4.100 to 6.900 kPa (600 to 1000 pounds per square inch) in single-fluid nozzles and at pressures of 340 to 690 kPa (50 to 100 psi) in two-fluid nozzles. Steam or air is used as the atomizing fluid in the two-fluid nozzles. The slurry is sprayed at high pressure into a vertical drying tower having a stream of hot air of from 315 to 400°C (600 to 750°F). All spray drying equipment designed for detergent granule production incorporates the following components: spray drying tower, air heating and supply system, slurry atomizing and pumping equipment, product cooling equipment, and conveying equipment. Most towers designed for detergent production are countercurrent, with slurry introduced at the top and heated air introduced at the bottom. The towers are cylindrical with cone bottoms and range in size from 4 to 7 meters (12 to 24 feet) in diameter and 12 to 38 meters (40 to 125 feet) in height. The detergent granules are conveyed mechanically or by air from the tower to a mixer to incorporate additional dry or liquid ingredients, and finally to packaging and storage.

5.15.3 Emissions And Controls

5.15.3.1 Soap[1,3,6]

The main atmospheric pollution problem in soap manufacturing is odor. The storage and handling of liquid ingredients (including sulfonic acids and salts) and sulfates are some of the sources of this odor. Vent lines, vacuum exhausts, raw material and product storage, and waste streams are all potential odor sources. Control of these odors may be achieved by scrubbing exhaust fumes and, if necessary, incinerating the remaining VOCs. Odors emanating from the spray dryer may be controlled by scrubbing with an acid solution. Blending, mixing, drying, packaging and other physical operations may all involve
dust emissions. The production of soap powder by spray drying is the single largest source of dust in the manufacture of synthetic detergents. Dust emissions from other finishing operations can be controlled by dry filters such as baghouses. The large sizes of the particulate from synthetic detergent drying means that high efficiency cyclones installed in series can achieve satisfactory control.

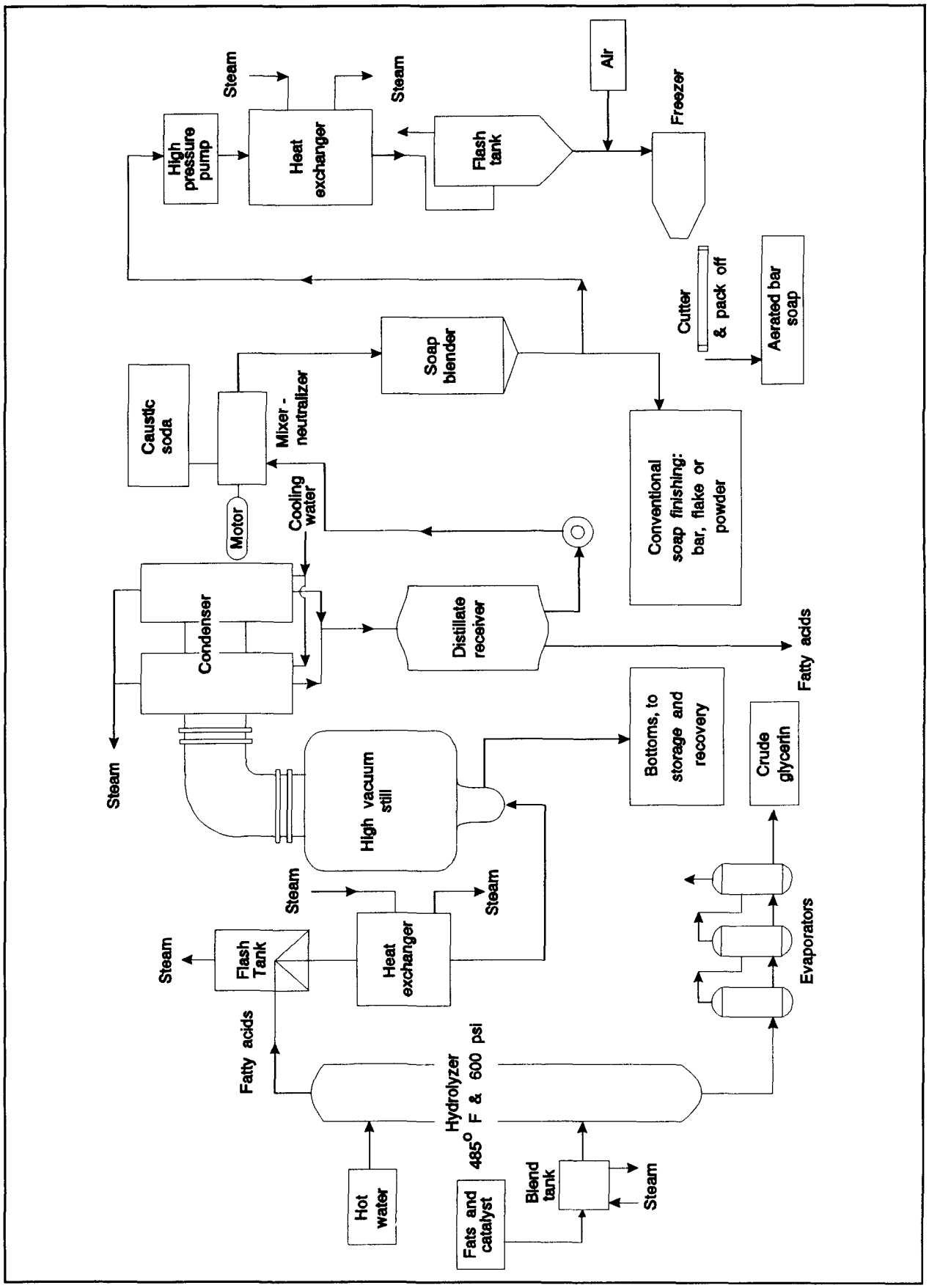


Figure 5.15-1. Continuous process for fatty acids and soaps.

Currently, no emission factors are available for soap manufacturing. No information on hazardous air pollutants (HAPs), volatile organic compounds (VOCs), ozone depleters, or heavy metal emissions information were found for soap manufacturing.

5.15.3.2 Detergent[1,3,4,6,8]

The exhaust air from detergent spray drying towers contains two types of air contaminants: 1) fine detergent particles and 2) organics vaporized in the higher temperature zones of the tower. Emission factors for particulates from spray drying operations are shown in Table 5.15-1.

Dust emissions are generated at scale hoppers, mixers, and crutchers during the batching and mixing of fine dry ingredients to form slurry. Conveying, mixing, and packaging of detergent granules can also cause dust emissions. Pneumatic conveying of fine materials causes dust emissions when conveying air is separated from bulk solids. For this process, fabric filters are generally used, not only to reduce or to eliminate dust emissions, but also to recover raw materials. The dust emissions principally consist of detergent compounds, although some of the particles are uncombined phosphates, sulfates, and other mineral compounds.

Dry cyclones and cyclonic impingement scrubbers are the primary collection equipment employed to capture the detergent dust in the spray dryer exhaust for return to processing. Dry cyclones are used in parallel or in series to collect this particulate and recycle it back to the crutcher. The dry cyclone separators can remove 90 percent or more by weight of the detergent product fines from the exhaust air. Cyclonic impinged scrubbers are used in parallel to collect the particulate from a scrubbing slurry and to recycle it to the crutcher.

Secondary collection equipment is used to collect fine particulates that escape from primary devices. For example, cyclonic impingement scrubbers are often followed by mist eliminators, and dry cyclones are followed by fabric filters or scrubber/electrostatic precipitator units. Several types of scrubbers can be used following the cyclone collectors. Venturi scrubbers have been used but are being replaced with packed bed scrubbers. Packed bed scrubbers are usually followed by wet-pipe-type electrostatic precipitators built immediately above the packed bed in the same vessel. Fabric filters have been used after cyclones but have limited applicability, especially on efficient spray dryers, due to condensing water vapor and organic aerosols binding the fabric filter.

In addition to particulate emissions, volatile organics may be emitted when the slurry contains organic materials with low vapor pressures. The VOCs originate primarily from the surfactants included in the slurry. The amount vaporized depends on many variables such as tower temperature, and the volatility of organics used in the slurry. These vaporized organic materials condense in the tower exhaust airstream into droplets or particles. Paraffin alcohols and amides in the exhaust stream can result in a highly visible plume that persists after the condensed water vapor plume has dissipated.

Opacity and the organics emissions are influenced by granule temperature and moisture at the end of drying, temperature profiles in the dryer, and formulation of the slurry. A method for controlling visible emissions would be to remove offending organic compounds (i. e., by substitution) from the slurry. Otherwise, tower production rate may be reduced thereby reducing air inlet temperatures and exhaust temperatures. Lowering production rate will also reduce organic emissions.

Some of the hazardous air pollutants (HAPs) and volatile organic compounds (VOCs) identified from the VOC/PM Speciate Database Management System (SPECIATE) are: hexane, methyl alcohol, 1,1,1-trichloroethane, perchloroethylene, benzene, and toluene. Lead was identified from SPECIATE

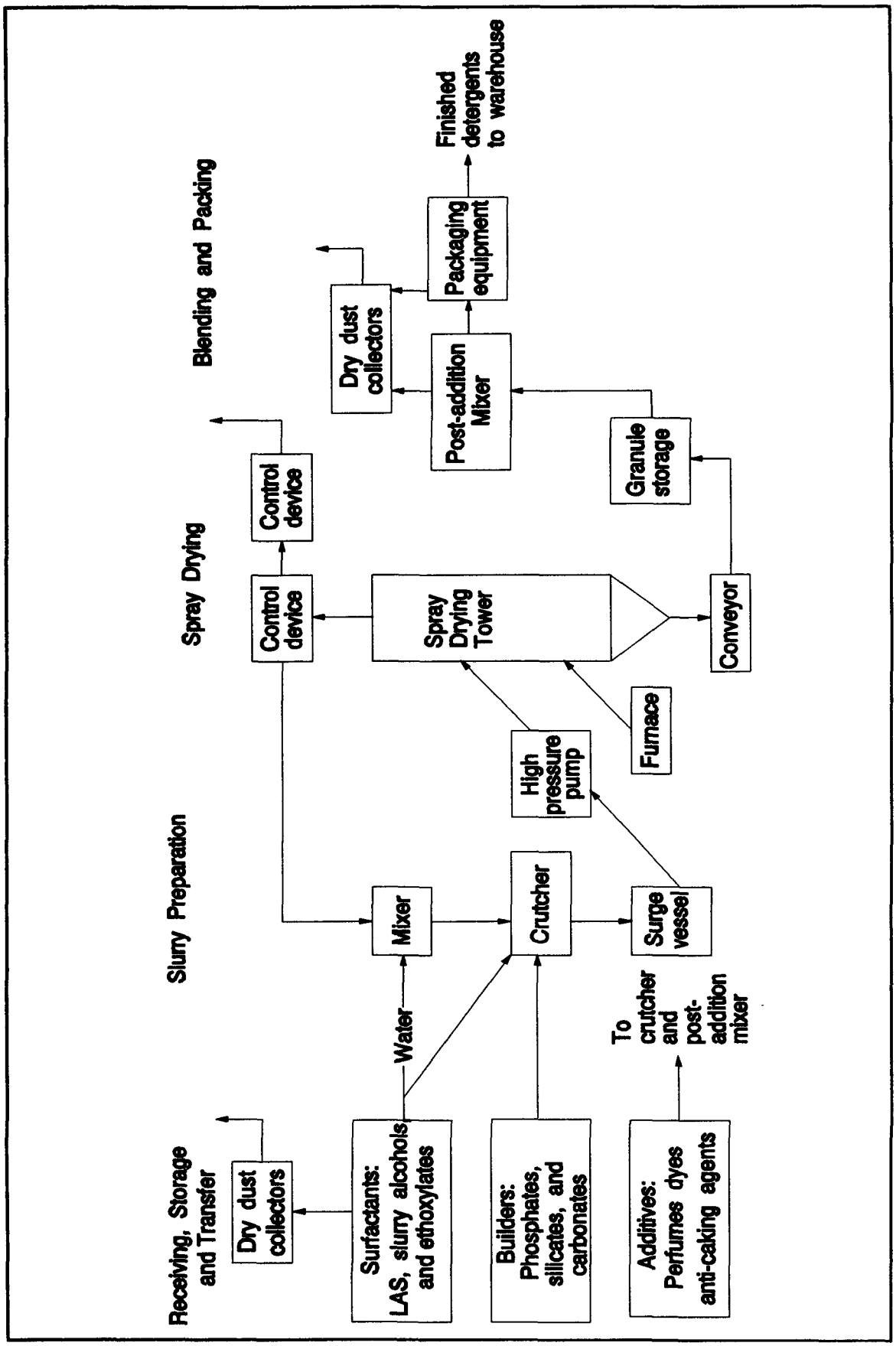


Figure 5.15-2. Manufacture of spray-dried detergents.

data as the only heavy metal constituent. No numerical data are presented for lead, HAP, or VOC emissions due to the lack of sufficient supporting documentation.

Table 5.15-1. (English and Metric Units).
PARTICULATE EMISSION FACTORS FOR DETERGENT SPRAY DRYING[a]

Control Device	Efficiency (%)	Particulate		Emission Factor Rating
		kg/Mg of Product	lb/ton of Product	
Uncontrolled		45	90	E[b]
Cyclone	85	7	14	E[b]
Cyclone with:				
Spray chamber	92	3.5	7	E[b]
Packed scrubber	95	2.5	5	E[b]
Venturi scrubber	97	1.5	3	E[b]
Wet scrubber	99	0.544	1.09	E[b]
Wet scrubber/ESP	99.9	0.023	0.046	E[b]
Packed bed/ESP	99	0.47	0.94	E[c]
Fabric filter	99	0.54	1.1	E[b]

[a]Some type of primary collector, such as a cyclone, is considered integral to a spray drying system. ESP = Electrostatic Precipitator.
[b]Emission Factors are estimations and are not supported by current test data.
[c]Emission factor has been calculated from a single source test. An efficiency of 99% has been estimated.

References for Section 5.15

1. *Source Category Survey: Detergent Industry*. EPA Contract No. 68-02-3059, June 1980.

2. A. H. Phelps, "Air Pollution Aspects Of Soap And Detergent Manufacture", APCA Journal, *17*, (8): 505-507. August 1967.

3. R. N. Shreve, *Third Edition: Chemical Process Industries*, McGraw-Hill Book Company, New York, NY.

4. J. H. Perry, *Fourth Edition: Chemical Engineers Handbook*, McGraw-Hill Book Company, New York, NY.

5. *Soap And Detergent Manufacturing: Point Source Category*, EPA-440/1-74-018-a, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1974.

6. J. A. Danielson, *Air Pollution Engineering Manual (2nd Edition)*, AP-40, U. S. Environmental Protection Agency, Research Triangle Park, NC. May 1973. Out of Print.

7. A. Lanteri, "Sulfonation And Sulfation Technology". Journal Of The American Oil Chemists Society, *55*, 128-132, January 1978.

8. A. J. Buonicore and W. T. Davis, eds., *Air Pollution Engineering Manual*, Van Nostrand Reinhold, New York, NY, 1992.

9. *Emission Test Report, Procter And Gamble, Augusta, GA*, Georgia Department Of Natural Resources, Atlanta, GA, July 1988.

10. *Emission Test Report, Time Products, Atlanta, GA*, Georgia Department Of Natural Resources, Atlanta, GA, November 1988.

11. *AIRS Facility Subsystem Source Classification Codes And Emission Factor Listing For Criteria Air Pollutants*, U. S. Environmental Protection Agency, Research Triangle Park, NC, EPA-450/4-90-003, March 1990.

5.16 SODIUM CARBONATE

5.16.1 General

Sodium carbonate (Na_2CO_3), commonly referred to as soda ash, is one of the largest-volume mineral products in the U.S., with 1991 production of over 9 million Mg (10.2 million tons). Over 85 percent of this soda ash originates in Wyoming, with the remainder coming from Searles Valley, California. Soda ash is used primarily in the production of glass, chemicals, soaps and detergents, and by consumers. Demand depends to great extent upon the price of, and environmental issues surrounding, caustic soda, which is interchangeable with soda ash in many uses and is widely co-produced with chlorine (see section 5.5 Chlor-Alkali).

5.16.2 Process Description

Soda ash may be manufactured synthetically or from naturally occurring raw materials such as ore. Only one U.S. facility recovers small quantities of Na_2CO_3 synthetically as a byproduct of cresylic acid production. Other synthetic processes include the Solvay process, which involves saturation of brine with ammonia (NH_4) and carbon dioxide (CO_2) gas, and the Japanese ammonium chloride (NH_4Cl) coproduction process. Both of these synthetic processes result in ammonia emissions. Natural processes include the calcination of sodium bicarbonate ($NaHCO_3$), or nahcolite, a naturally-occurring ore found in vast quantities in Colorado.

The two processes presently used to produce natural soda ash differ only in the recovery and primary treatment of the raw material used. The raw material for Wyoming soda ash is mined trona ore, while California soda ash is derived from sodium carbonate-rich brine extracted from Searles Lake.

There are four distinct methods used to mine the Wyoming trona ore: 1) solution mining, 2) room-and-pillar, 3) longwall, and 4) shortwall. In solution mining, dilute sodium hydroxide (NaOH), commonly called caustic soda, is injected into the trona to dissolve it. This solution is treated with carbon dioxide gas in carbonation towers to convert the sodium carbonate (Na_2CO_3) in solution to sodium bicarbonate ($NaHCO_3$), which precipitates and is filtered out. The crystals are again dissolved in water, precipitated with carbon dioxide, and filtered. The product is calcined to produce dense soda ash. Brine extracted from below Searles Lake in California is treated similarly.

For the room-and-pillar, longwall, and shortwall methods, the conventional blasting agent is prilled ammonium nitrate (NH_4NO_3) and fuel oil, or ANFO (see section 11.3 "Explosives Detonation"). Beneficiation is accomplished with either of two methods called the sesquicarbonate and the monohydrate processes. In the sesquicarbonate process, shown schematically in Figure 5.16-1, trona ore is first dissolved in water and then treated as brine. The liquid is filtered to remove insoluble impurities before the sodium sesquicarbonate ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$) is precipitated out using vacuum crystallizers. The result is centrifuged to remove remaining water, and can be sold as a finished product or further calcined to yield soda ash of light to intermediate density. In the monohydrate process, shown schematically in Figure 5.16-2, the crushed trona is calcined in a rotary kiln, yielding dense soda ash and carbon dioxide and water as by-products. The calcined material is combined with water to allow settling out or filtering of impurities such as shale, and is then

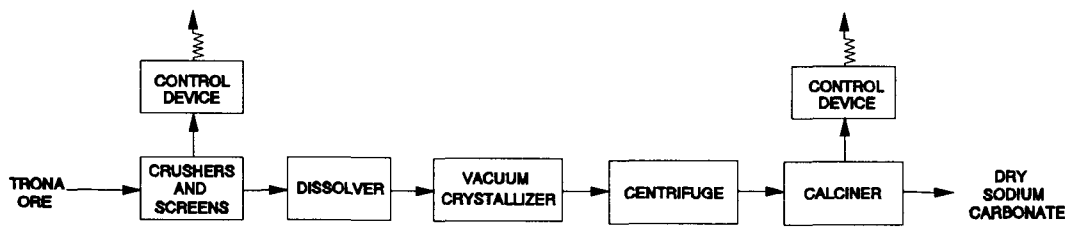


Figure 5.16-1 Flow diagram for sesquicarbonate sodium carbonate processing

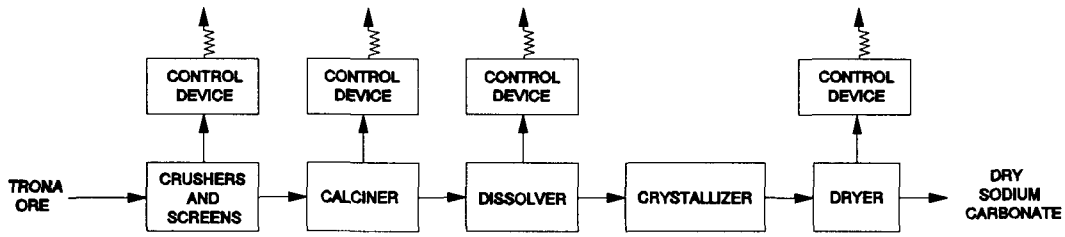


Figure 5.16-2 Flow diagram for monohydrate sodium carbonate processing

concentrated by triple-effect evaporators and/or mechanical vapor recompression crystallizers to precipitate sodium carbonate monohydrate ($Na_2CO_3 \cdot H_2O$). Impurities such as sodium chloride (NaCl) and sodium sulfate (Na_2SO_4)remain in solution. The crystals and liquor are centrifuged, and the recovered crystals are calcined again to remove remaining water. The product must then be cooled, screened, and possibly bagged before shipping.

5.16.3 Emissions and Controls

The principal air emissions from the sodium carbonate production methods presently used in the U.S. are particulate emissions from the ore calciners; soda ash coolers and dryers; ore crushing, screening, and transporting operations; and product handling and shipping operations. Emissions of products of combustion, such as carbon monoxide, nitrogen oxides, sulfur dioxide, and carbon dioxide occur from direct-fired process heating units such as ore calcining kilns and soda ash dryers. With the exception of carbon dioxide, which is suspected of contributing to global climate change, insufficient data are available to quantify these emissions with a reasonable level of confidence, but similar processes are addressed in various sections of Chapter 8 of AP-42 (*Mineral Products Industries*). Emissions of filterable and total particulate matter from individual processes and process

components are quantified in Table 5.16-1 on a controlled (as-measured) basis. Emissions of total particulate matter from these same processes are quantified in Table 5.16-2 on an uncontrolled basis. No data quantifying emissions of organic condensible particulate matter from sodium carbonate manufacturing processes are available, but this portion of the particulate matter can be assumed to be negligible. Emissions of carbon dioxide from selected processes are quantified in Table 5.16-3. Emissions from combustion sources such as boilers, and from evaporation of hydrocarbon fuels used to fire these combustion sources, are covered in other chapters of AP-42.

Particulate emissions from calciners and dryers are typically controlled by venturi scrubbers, electrostatic precipitators, and/or cyclones. Baghouse filters are not well suited to applications such as these, due to the high moisture content of the effluent gas. Particulate emissions from the ore and product handling operations are typically controlled by either venturi scrubbers or baghouse filters. These control devices are an integral part of the manufacturing process, capturing raw materials and product for economic reasons. Due to a lack of suitable emissions data for uncontrolled processes, controlled emission factors are presented for this industry in addition to uncontrolled emission factors. The uncontrolled emission factors have been calculated by applying nominal control efficiencies to the controlled emission factors.

Table 5.16-1 (Metric Units)
PARTICULATE MATTER: CONTROLLED BASIS

Process (SCC Code)	Filterable[a]		Total[b]	
	kg/Mg of Product	Emission Factor Rating	kg/Mg of Product	Emission Factor Rating
Ore mining[c] (3-01-023-99)	0.0016	C	N/A[d]	N/A[d]
Ore crushing and screening[c] (3-01-023-99)	0.0010	D	0.0018	C
Ore transfer[c] (3-01-023-99)	0.00008	E	0.0001	E
Monohydrate process: rotary ore calciner (3-01-023-04/05)	0.091	A	0.12	B
Sesquicarbonate process: rotary calciner (3-01-023-99)	0.36	B	0.36	C
Sesquicarbonate process: fluid-bed calciner (3-01-023-99)	0.021	C	N/A[d]	N/A[d]
Rotary soda ash dryers (3-01-023-06)	0.25	C	0.25	D
Fluid-bed soda ash dryers/coolers (3-01-023-07)	0.015	C	0.019	D
Soda ash screening (3-01-023-99)	0.0097	E	0.013	E
Soda ash storage/loading and unloading[c] (3-01-023-99)	0.0021	E	0.0026	E

[a] Filterable particulate matter is that material collected in the probe and filter of a method 5 or Method 17 sampler

[b] Total particulate matter includes filterable particulate and inorganic condensible particulate.

[c] For ambient temperature processes, all particulate matter emissions can be assumed to be filterable at ambient conditions; however, particulate sampling according to EPA Reference Method 5 involves the heating of the front half of the sampling train to temperatures that may vaporize some portion of this particulate matter, which will then recondense in the back half of the sampling train. For consistency, particulate matter measured as condensible according to Method 5 is reported as such.

[d] N/A = data not available.

Table 5.16-1 (English Units)
PARTICULATE MATTER: CONTROLLED BASIS

Process (SCC Code)	Filterable[a]		Total[b]	
	lb/ton of Product	Emission Factor Rating	lb/ton of Product	Emission Factor Rating
Ore mining[c] (3-01-023-99)	0.0033	C	N/A[d]	N/A[d]
Ore crushing and screening[c] (3-01-023-99)	0.0021	D	0.0035	C
Ore transfer[c] (3-01-023-99)	0.0002	E	0.0002	E
Monohydrate process: rotary ore calciner (3-01-023-04/05)	0.18	A	0.23	B
Sesquicarbonate process: rotary calciner (3-01-023-99)	0.72	B	0.73	C
Sesquicarbonate process: fluid-bed calciner (3-01-023-99)	0.043	C	N/A[d]	N/A[d]
Rotary soda ash dryers (3-01-023-06)	0.50	C	0.52	D
Fluid-bed soda ash dryers/coolers (3-01-023-07)	0.030	C	0.39	D
Soda ash screening (3-01-023-99)	0.019	E	0.026	E
Soda ash storage/loading and unloading[c] (3-01-023-99)	0.0041	E	0.0051	E

[a] Filterable particulate matter is that material collected in the probe and filter of a method 5 or Method 17 sampler

[b] Total particulate matter includes filterable particulate and inorganic condensible particulate.

[c] For ambient temperature processes, all particulate matter emissions can be assumed to be filterable at ambient conditions; however, particulate sampling according to EPA Reference Method 5 involves the heating of the front half of the sampling train to temperatures that may vaporize some portion of this particulate matter, which will then recondense in the back half of the sampling train. For consistency, particulate matter measured as condensible according to Method 5 is reported as such.

[d] N/A = data not available.

TABLE 5.16-2
PARTICULATE MATTER: UNCONTROLLED BASIS

Process (SCC Code)	Nominal Control Efficiency (percent)	Total[a]		
		kg/Mg of Product	lb/ton of Product	Emission Factor Rating
Ore mining (3-01-023-99)		1.6	3.3	D
Ore crushing and screening (3-01-023-99)		1.7	3.5	E
Ore transfer (3-01-023-99)		0.1	0.2	E
Monohydrate process: rotary ore calciner (3-01-023-04/05)	99.9	90	180	B
Sesquicarbonate process: rotary calciner (3-01-023-99)		36	72	D
Sesquicarbonate process: fluid-bed calciner (3-01-023-99)		2.1	4.3	D
Rotary soda ash dryers (3-01-023-06)		25	50	E
Fluid-bed soda ash dryers/coolers (3-01-023-07)	99	1.5	3.0	E
Soda ash screening (3-01-023-99)		10	19	E
Soda ash storage/loading and unloading (3-01-023-99)	99.9	2.6	5.2	E

[a] Values for total particulate matter on an uncontrolled basis can be assumed to include filterable particulate and both organic and inorganic condensible particulate. For processes operating at significantly greater than ambient temperatures, these factors have been calculated by applying the nominal control efficiency to the controlled (as-measured) filterable particulate emission factors above.

TABLE 5.16-3 (METRIC UNITS)
CARBON DIOXIDE[a]

Process (SCC Code)	Carbon Dioxide		
	kg/Mg of Product	lb/ton of Product	Emission Factor Rating
Monohydrate process: rotary ore calciner (3-01-023-04/05)	200	400	E
Sesquicarbonate process: rotary calciner (3-01-023-99)	150	310	E
Sesquicarbonate process: fluid-bed calciner (3-01-023-99)	90	180	E
Rotary soda ash dryers (3-01-023-06)	63	130	E

[a] Emission factors for carbon dioxide are derived from ORSAT analyses during emission tests for criteria pollutants, rather than from fuel analyses and material balances.

References for Section 5.16

1. D.S. Kostick, "Soda Ash," *Mineral Commodity Summaries 1992*, pp. 162-163, U.S Department of the Interior, Bureau of Mines, 1992.

2. D.S. Kostick, "Soda Ash," *Minerals Yearbook 1989, Volume I: Metals and Minerals*, pp. 951-968, U.S Department of the Interior, Bureau of Mines, 1990.

3. SRI International, *1990 Directory of Chemical Producers: United States.*

4. L. Gribovicz, Wyoming Department of Environmental Quality, Air Quality Division, "FY 91 Annual Inspection Report: FMC-Wyoming Corporation, Westvaco Soda Ash Refinery," 11 June 1991.

5. L. Gribovicz, Wyoming Department of Environmental Quality, Air Quality Division, "FY 92 Annual Inspection Report: General Chemical Partners, Green River Works," 16 September 1991.

6. L. Gribovicz, Wyoming Department of Environmental Quality, Air Quality Division, "FY 92 Annual Inspection Report: Rhône-Poulenc Chemical Company, Big Island Mine and Refinery," 17 December 1991.

7. L. Gribovicz, Wyoming Department of Environmental Quality, Air Quality Division, "FY 91 Annual Inspection Report: Texasgulf Chemical Company, Granger Trona Mine & Soda Ash Refinery," 15 July 1991.

8. "Stack Emissions Survey: General Chemical, Soda Ash Plant, Green River, Wyoming," Western Environmental Services and Testing, Inc., Casper, WY, February 1988.

9. "Stack Emissions Survey: General Chemical, Soda Ash Plant, Green River, Wyoming," Western Environmental Services and Testing, Inc., Casper, WY, November 1989.

10. "Rhône-Poulenc Wyoming Co. Particulate Emission Compliance Program," TRC Environmental Measurements Division, Englewood, CO, 21 May 1990.

11. "Rhône-Poulenc Wyoming Co. Particulate Emission Compliance Program," TRC Environmental Measurements Division, Englewood, CO, 6 July 1990.

12. "Stack Emissions Survey: FMC-Wyoming Corporation, Green River, Wyoming," FMC-Wyoming Corporation, Green River, WY, October 1990.

13. "Stack Emissions Survey: FMC-Wyoming Corporation, Green River, Wyoming," FMC-Wyoming Corporation, Green River, WY, February 1991.

14. "Stack Emissions Survey: FMC-Wyoming Corporation, Green River, Wyoming," FMC-Wyoming Corporation, Green River, WY, January 1991.

15. "Stack Emissions Survey: FMC-Wyoming Corporation, Green River, Wyoming," FMC-Wyoming Corporation, Green River, WY, October 1990.

16. "Compliance Test Report: FMC-Wyoming Corporation, Green River, Wyoming," FMC-Wyoming Corporation, Green River, WY, 6 June 1988.

17. "Compliance Test Report: FMC-Wyoming Corporation, Green River, Wyoming," FMC-Wyoming Corporation, Green River, WY, 24 May 1988.

18. "Compliance Test Report: FMC-Wyoming Corporation, Green River, Wyoming," FMC-Wyoming Corporation, Green River, WY, 28 August 1985.

19. "Stack Emissions Survey: FMC-Wyoming Corporation, Green River, Wyoming," FMC-Wyoming Corporation, Green River, WY, December 1990.

20. "Emission Measurement Test Report of GR3A Crusher," The Emission Measurement People, Inc.," Cañon City, CO, 16 October 1990.

21. "Stack Emissions Survey: TG Soda Ash, Inc., Granger, Wyoming," Western Environmental Services and Testing, Inc., Casper, WY, August 1989.

22. "Compliance Test Reports," Tenneco Minerals, Green River, WY, 30 November 1983.

23. "Compliance Test Reports," Tenneco Minerals, Green River, WY, 8 November 1983.

24. "Particulate Stack Sampling Reports," Texasgulf, Inc., Granger, WY, October 1977-September 1978.

25. "Fluid Bed Dryer Emissions Certification Report," Texasgulf Chemicals Co., Granger, WY, 18 February 1985.

26. "Stack Emissions Survey: General Chemical, Soda Ash Plant, Green River, Wyoming," Western Environmental Services and Testing, Inc., Casper, WY, May 1987.

5.17 SULFURIC ACID

5.17.1 General[1-2]

Sulfuric acid (H_2SO_4) is a basic raw material used in a wide range of industrial processes and manufacturing operations. Almost 70 percent of sulfuric acid manufactured is used in the production of phosphate fertilizers. Other uses include copper leaching, inorganic pigment production, petroleum refining, paper production, and industrial organic chemical production.

Sulfuric acid may be manufactured commercially by either the lead chamber process or the contact process. Because of economics, all of the sulfuric acid produced in the U. S. is now produced by the contact process. U. S. facilities produce approximately 42 million megagrams (46.2 million tons) of H_2SO_4 annually. Growth in demand was about 1 percent per year from 1981 to 1991 and is projected to continue to increase at about 0.5 percent per year.

5.17.2 Process Description[3-5]

Since the contact process is the only process currently used, it will be the only one discussed in this section. Contact plants are classified according to the raw materials charged to them: elemental sulfur burning, spent sulfuric acid and hydrogen sulfide burning, and metal sulfide ores and smelter gas burning. The contributions from these plants to the total acid production are 81, 8 and 11 percent, respectively.

The contact process incorporates three basic operations, each of which corresponds to a distinct chemical reaction. First, the sulfur in the feedstock is oxidized (burned) to sulfur dioxide:

$$S + O_2 \rightarrow SO_2 \quad (1)$$

The resulting sulfur dioxide is fed to a process unit called a converter, where it is catalytically oxidized to sulfur trioxide:

$$2SO_2 + O_2 \rightarrow 2SO_3 \quad (2)$$

Finally, the sulfur trioxide is absorbed in a strong sulfuric acid (98 percent) solution:

$$SO_3 + H_2O \rightarrow H_2SO_4 \quad (3)$$

5.17.2.1 Elemental Sulfur Burning Plants

Figure 5.17-1 is a schematic diagram of a dual absorption contact process sulfuric acid plant that burns elemental sulfur. In the Frasch process, elemental sulfur is melted, filtered to remove ash, and sprayed under pressure into a combustion chamber. The sulfur is burned in clean air that has been dried by scrubbing with 93 to 99 percent sulfuric acid. The gases from the combustion chamber cool by passing through a waste heat boiler and then enter the catalyst (vanadium pentoxide) converter. Usually, 95 to 98 percent of the sulfur dioxide from the combustion chamber is converted to sulfur trioxide, with an accompanying large evolution of heat. After being cooled, again by

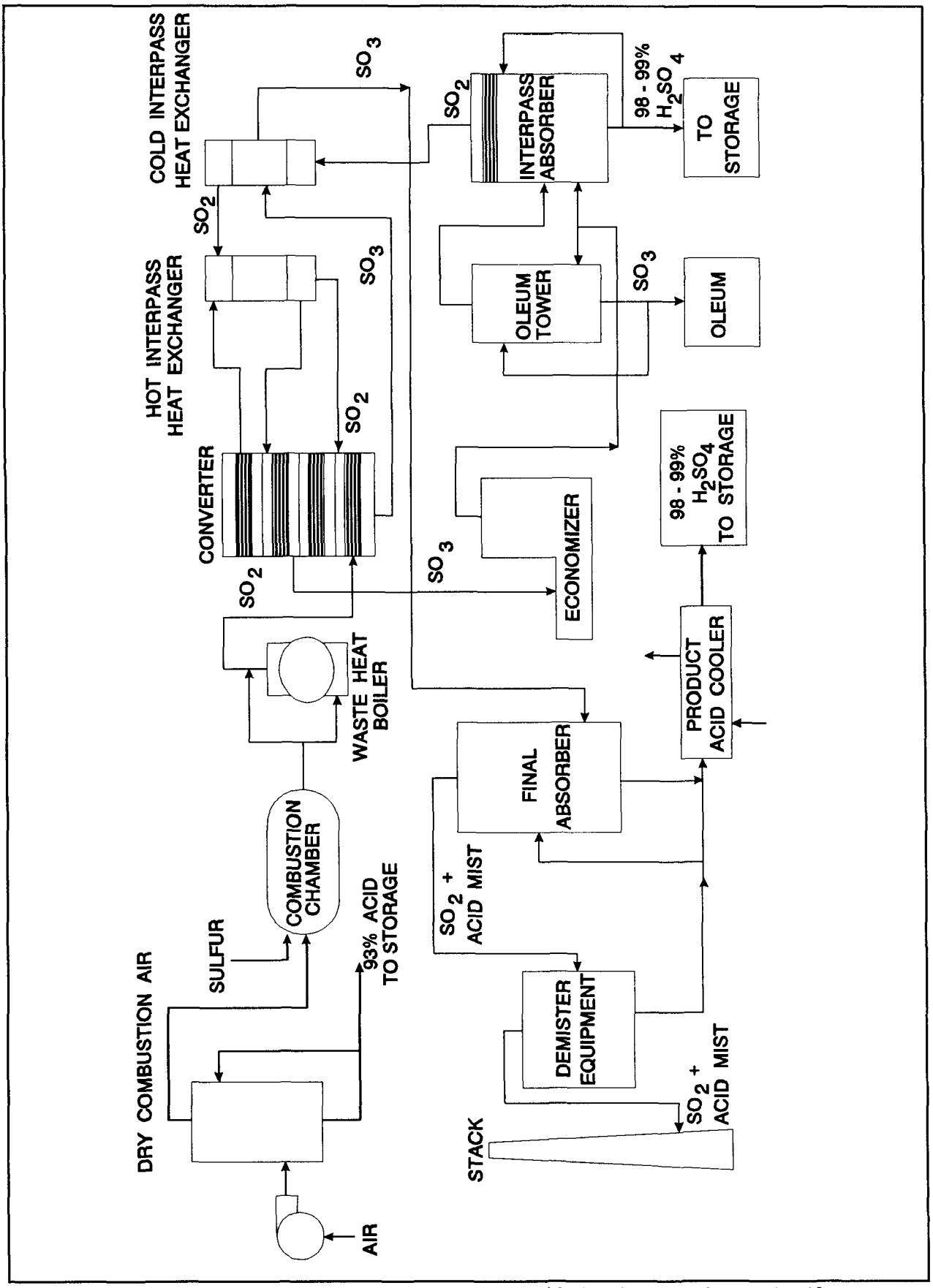


Figure 5.17-1. Typical contact process sulfuric acid plant burning elemental sulfur.

generating steam, the converter exit gas enters an absorption tower. The absorption tower is a packed column where acid is sprayed in the top and where the sulfur trioxide enters from the bottom. The sulfur trioxide is absorbed in the 98 to 99 percent sulfuric acid. The sulfur trioxide combines with the water in the acid and forms more sulfuric acid.

If oleum (a solution of uncombined SO_3 dissolved in H_2SO_4) is produced, SO_3 from the converter is first passed to an oleum tower that is fed with 98 percent acid from the absorption system. The gases from the oleum tower are then pumped to the absorption column where the residual sulfur trioxide is removed.

In the dual absorption process shown in Figure 5.17-1, the SO_3 gas formed in the primary converter stages is sent to an interpass absorber where most of the SO_3 is removed to form H_2SO_4. The remaining unconverted sulfur dioxide is forwarded to the final stages in the converter to remove much of the remaining SO_2 by oxidation to SO_3, whence it is sent to the final absorber for removal of the remaining sulfur trioxide. The single absorption process uses only one absorber, as the name implies.

5.17.2.2 Spent Acid And Hydrogen Sulfide Burning Plants

A schematic diagram of a contact process sulfuric acid plant that burns spent acid is shown in Figure 5.17-2. Two types of plants are used to process this type of sulfuric acid. In one, the sulfur dioxide and other products from the combustion of spent acid and/or hydrogen sulfide with undried atmospheric air are passed through gas cleaning and mist removal equipment. The gas stream next passes through a drying tower. A blower draws the gas from the drying tower and discharges the sulfur dioxide gas to the sulfur trioxide converter, then to the oleum tower and/or absorber.

In a "wet gas plant", the wet gases from the combustion chamber are charged directly to the converter, with no intermediate treatment. The gas from the converter flows to the absorber, through which 93 to 98 percent sulfuric acid is circulated.

5.17.2.3 Sulfide Ores And Smelter Gas Plants

The configuration of this type of plant is essentially the same as that of a spent acid plant (Figure 5.17-2), with the primary exception that a roaster is used in place of the combustion furnace.

The feed used in these plants is smelter gas, available from such equipment as copper converters, reverberatory furnaces, roasters and flash smelters. The sulfur dioxide in the gas is contaminated with dust, acid mist and gaseous impurities. To remove the impurities, the gases must be cooled and passed through purification equipment consisting of cyclone dust collectors, electrostatic dust and mist precipitators, and scrubbing and gas cooling towers. After the gases are cleaned and the excess water vapor is removed, they are scrubbed with 98 percent acid in a drying tower. Beginning with the drying tower stage, these plants are nearly identical to the elemental sulfur plants shown in Figure 5.17-1.

5.17.3 Emissions[4,6-7]

5.17.3.1 Sulfur Dioxide

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

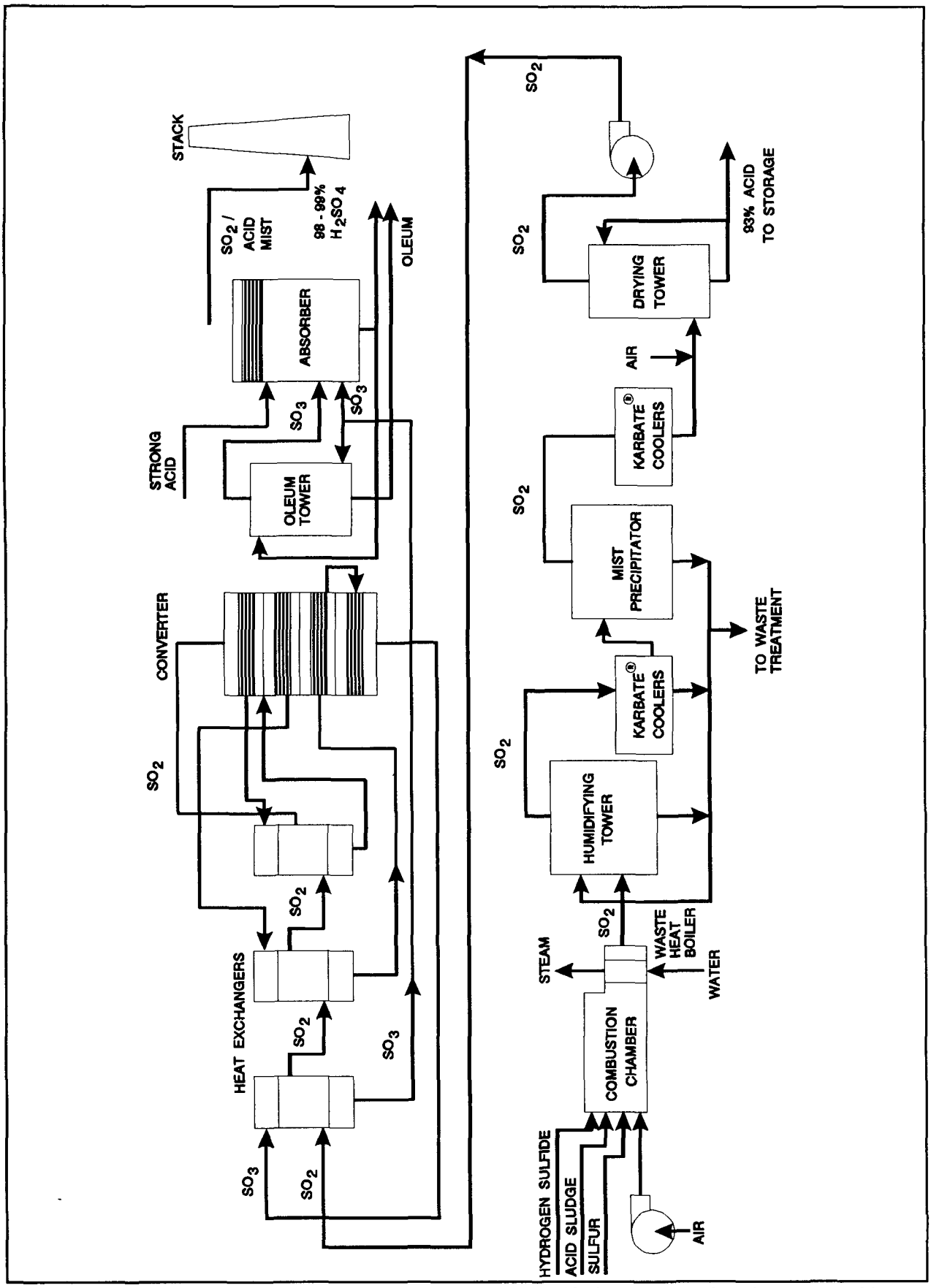


Figure 5.17-2. Basic flow diagram of contact process sulfuric acid plant burning spent acid.

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). For example, if the inlet SO_2 concentration to the converter were 9 percent by volume (a representative value), and the conversion temperature was 430°C (806°F), the conversion efficiency would be 98 percent. At this conversion, Table 5.17-1 shows that the uncontrolled emission factor for SO_2 would be 13 kg/Mg (26 pounds per ton) of 100 percent sulfuric acid produced. (For purposes of comparison, note that the Agency's new source performance standard (NSPS) for new and modified plants is 2 kg/Mg (4 pounds per ton) of 100 percent acid produced, maximum 2 hour average). As Table 5.17-1 and Figure 5.17-3 indicate, achieving this standard requires a conversion efficiency of 99.7 percent in an uncontrolled plant, or the equivalent SO_2 collection mechanism in a controlled facility.

Dual absorption, as discussed above, has generally been accepted as the Best Available Control Technology (BACT) for meeting NSPS emission limits. There are no by-products or waste scrubbing materials created, only additional sulfuric acid. Conversion efficiencies of 99.7 percent and higher are achievable, whereas most single absorption plants have SO_2 conversion efficiencies ranging only from 95 to 98 percent. Furthermore, dual absorption permits higher converter inlet sulfur dioxide concentrations than are used in single absorption plants, because the final conversion stages effectively remove any residual sulfur dioxide from the interpass absorber.

In addition to exit gases, small quantities of sulfur oxides are emitted from storage tank vents and tank car and tank truck vents during loading operations, from sulfuric acid concentrators, and through leaks in process equipment. Few data are available on the quantity of emissions from these sources.

Table 5.17-1 (Metric and English Units).
SULFUR DIOXIDE EMISSION FACTORS FOR SULFURIC ACID PLANTS[a]

SO_2 to SO_3 Conversion Efficiency (%)		SO_2 Emissions[b]		Emission Factor Rating
		kg/Mg of Product	lb/ton of Product	
93	(SCC 3-01-023-18)	48.0	96	E
94	(SCC 3-01-023-16)	41.0	82	E
95	(SCC 3-01-023-14)	35.0	70	E
96	(SCC 3-01-023-12)	27.5	55	E
97	(SCC 3-01-023-10)	20.0	40	E
98	(SCC 3-01-023-08)	13.0	26	E
99	(SCC 3-01-023-06)	7.0	14	E
99.5	(SCC 3-01-023-04)	3.5	7	E
99.7		2.0	4	E
100	(SCC 3-01-023-01)	0.0	0.0	E

[a]Reference 3. SCC = Source Classification Code.
[b]This linear interpolation formula can be used for calculating emission factors for conversion efficiencies between 93 and 100%: emission factor = -13.65 (% conversion efficiency) + 1365.

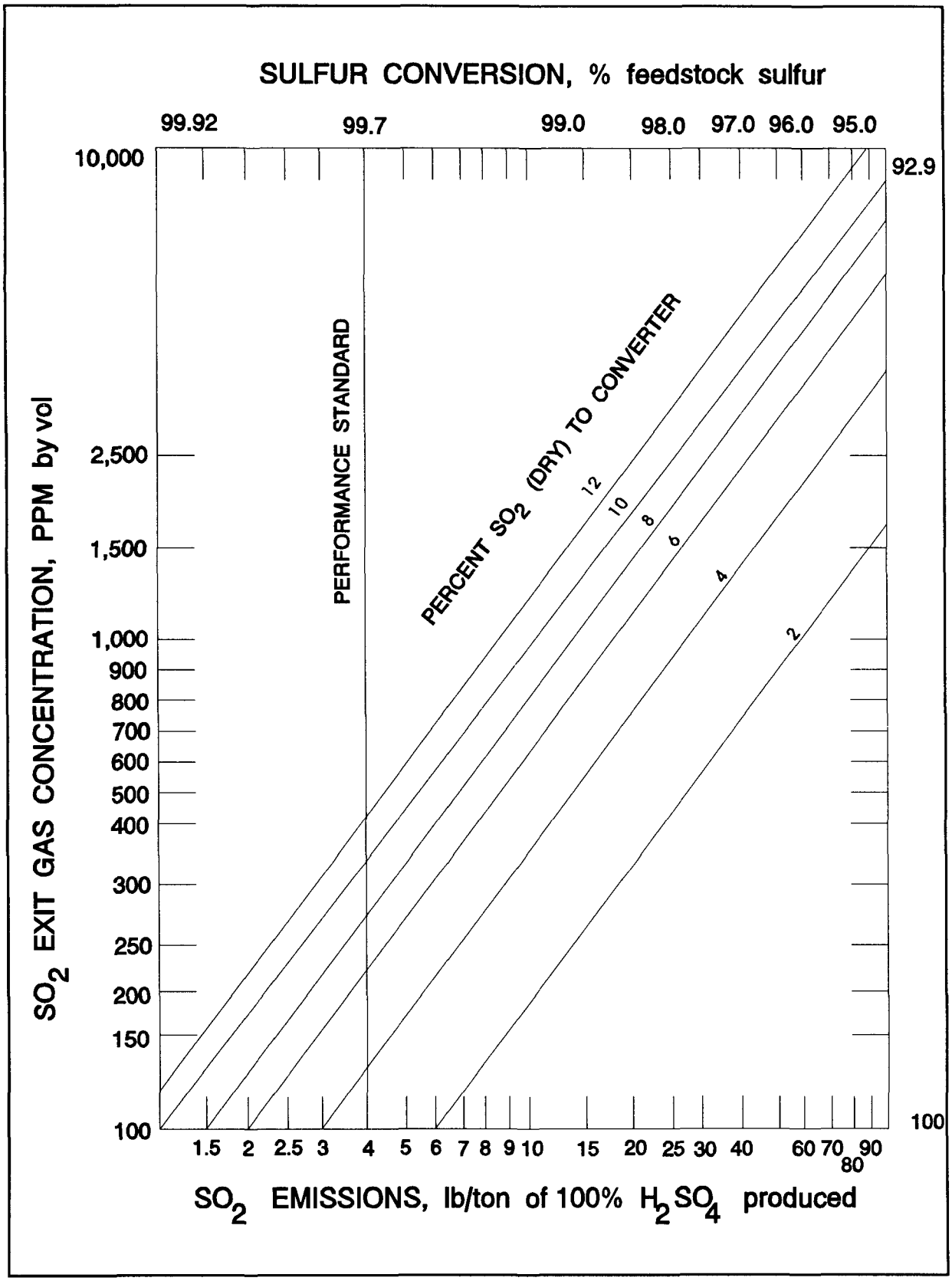


Figure 5.17-3. Sulfuric acid plant feedstock conversion versus volumetric and mass SO_2 emissions at various inlet SO_2 concentrations by volume.

5.17.3.2 Acid Mist

Nearly all the acid mist emitted from sulfuric acid manufacturing can be traced to the absorber exit gases. Acid mist is created when sulfur trioxide combines with water vapor at a temperature below the dew point of sulfur trioxide. Once formed within the process system, this mist is so stable that only a small quantity can be removed in the absorber.

In general, the quantity and particle size distribution of acid mist are dependent on the type of sulfur feedstock used, the strength of acid produced, and the conditions in the absorber. Because it contains virtually no water vapor, bright elemental sulfur produces little acid mist when burned. However, the hydrocarbon impurities in other feedstocks (i. e., dark sulfur, spent acid and hydrogen sulfide) oxidize to water vapor during combustion. The water vapor, in turn, combines with sulfur trioxide as the gas cools in the system.

The strength of acid produced, whether oleum or 99 percent sulfuric acid, also affects mist emissions. Oleum plants produce greater quantities of finer more stable mist. For example, an unpublished report found that uncontrolled mist emissions from oleum plants burning spent acid range from 0.5 to 5.0 kg/Mg (1.0 to 10.0 pounds per ton), while those from 98 percent acid plants burning elemental sulfur range from 0.2 to 2.0 kg/Mg (0.4 to 4.0 pounds per ton).[4] Furthermore, 85 to 95 weight percent of the mist particles from oleum plants are less than two microns in diameter, compared with only 30 weight percent that are less than two microns in diameter from 98 percent acid plants.

The operating temperature of the absorption column directly affects sulfur trioxide absorption and, accordingly, the quality of acid mist formed after exit gases leave the stack. The optimum absorber operating temperature depends on the strength of the acid produced, throughput rates, inlet sulfur trioxide concentrations, and other variables peculiar to each individual plant. Finally, it should be emphasized that the percentage conversion of sulfur trioxide has no direct effect on acid mist emissions.

Table 5.17-2 presents uncontrolled acid mist emission factors for various sulfuric acid plants. Table 5.17-3 shows emission factors for plants that use fiber mist eliminator control devices. The three most commonly used fiber mist eliminators are the vertical tube, vertical panel, and horizontal dual pad types. They differ from one another in the arrangement of the fiber elements, which are composed of either chemically resistant glass or fluorocarbon, and in the means employed to collect the trapped liquid. Data are available only with percent oleum ranges for two raw material categories.

5.17.3.3 Carbon Dioxide

The nine source tests mentioned above were also used to determine the amount of carbon dioxide (CO_2), a global warming gas, emitted by sulfuric acid production facilities. Based on the tests, a CO_2 emission factor of 4.05 kg emitted per Mg produced (8.10 lb/ton) was developed, with an emission factor rating of C.

Table 5.17-2 (Metric and English Units).
UNCONTROLLED ACID MIST EMISSION FACTORS FOR SULFURIC ACID PLANTS[a]

Raw Material	Oleum Produced, % total output	Emissions[b]		Emission Factor Rating
		kg/Mg of Product	lb/ton of Product	
Recovered sulfur (SCC 3-01-023-22)	0 to 43	0.174 - 0.4	0.348 - 0.8	E
Bright virgin sulfur (SCC 3-01-023-22)	0	0.85	1.7	E
Dark virgin sulfur (SCC 3-01-023-22)	0 to 100	0.16 - 3.14	0.32 - 6.28	E
Spent acid (SCC 3-01-023-22)	0 to 77	1.1 - 1.2	2.2 - 2.4	E

[a]Reference 3. SCC = Source Classification Code.
[b]Emissions are proportional to the percentage of oleum in the total product. Use low end of ranges for low oleum percentage and high end of ranges for high oleum percentage.

Table 5.17-3 (Metric and English Units).
CONTROLLED ACID MIST EMISSION FACTORS FOR SULFURIC ACID PLANTS

Raw Material	Oleum produced, % total output	Emissions		Emission Factor Rating
		kg/Mg of Product	lb/ton of Product	
Elemental Sulfur[a] (SCC 3-01-023-22)	-	0.064	0.128	C
Dark Virgin Sulfur[b] (SCC 3-01-023-22)	0 to 13	0.26 - 1.8	0.52 - 3.6	E
Spent Acid (SCC 3-01-023-22)	0 to 56	0.014 - 0.20	0.28 - 0.40	E

[a]Reference 8-13, 15-17. SCC = Source Classification Code.
[b]Reference 3.

References for Section 5.17

1. *Chemical Marketing Reporter*, Schnell Publishing Company, Inc., New York, *240*:8, September 16, 1991.

2. *Final Guideline Document: Control Of Sulfuric Acid Mist Emissions From Existing Sulfuric Acid Production Units*, EPA-450/2-77-019, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1977.

3. *Atmospheric Emissions From Sulfuric Acid Manufacturing Processes*, 999-AP-13, U. S. Department of Health, Education and Welfare, Washington, DC, 1966.

4. Unpublished report on control of air pollution from sulfuric acid plants, U. S. Environmental Protection Agency, Research Triangle Park, NC, August 1971.

5. *Review Of New Source Performance Standards For Sulfuric Acid Plants*, EPA-450/3-85-012, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1985.

6. *Standards Of Performance For New Stationary Sources*, 36 FR 24875, December 23, 1971.

7. "Sulfuric Acid", *Air Pollution Engineering Manual*, Air And Water Management Association, 1992.

8. *Source Emissions Compliance Test Report, Sulfuric Acid Stack*, Roy F. Weston, Inc., West Chester, PA, October 1989.

9. *Source Emissions Compliance Test Report, Sulfuric Acid Stack*, Roy F. Weston, Inc., West Chester, PA, February 1988.

10. *Source Emissions Compliance Test Report, Sulfuric Acid Stack*, Roy F. Weston, Inc., West Chester, PA, December 1989.

11. *Source Emissions Compliance Test Report, Sulfuric Acid Stack*, Roy F. Weston, Inc., West Chester, PA, December 1991.

12. *Stationary Source Sampling Report, Sulfuric Acid Plant*, Entropy Environmentalists, Inc., Research Triangle Park, NC, January 1983.

13. *Source Emissions Test: Sulfuric Acid Plant*, Ramcon Environmental Corporation, Memphis, TN, October 1989.

14. *Mississippi Chemical Corporation, Air Pollution Emission Tests, Sulfuric Acid Stack*, Environmental Science and Engineering, Inc., Gainesville, FL, September 1973.

15. *Kennecott Copper Corporation, Air Pollution Emission Tests, Sulfuric Acid Stack - Plant 6*, Engineering Science, Inc., Washington, DC, August 1972.

16. *Kennecott Copper Corporation, Air Pollution Emission Tests, Sulfuric Acid Stack - Plant 7*, Engineering Science, Inc., Washington, DC, August 1972.

17. *American Smelting Corporation, Air Pollution Emission Tests, Sulfuric Acid Stack*, Engineering Science, Inc., Washington, DC, June 1972.

5.18 SULFUR RECOVERY

5.18.1 General[1-2]

Sulfur recovery refers to the conversion of hydrogen sulfide (H_2S) to elemental sulfur. Hydrogen sulfide is a byproduct of processing natural gas and refining high-sulfur crude oils. The most common conversion method used is the Claus process. Approximately 90 to 95 percent of recovered sulfur is produced by the Claus process. The Claus process typically recovers 95 to 97 percent of the hydrogen sulfide feedstream.

Over 5.9 million megagrams (6.5 million tons) of sulfur were recovered in 1989, representing about 63 percent of the total elemental sulfur market in the U.S. The remainder was mined or imported. The average production rate of a sulfur recovery plant in the U.S. varies from 51 to 203 megagrams (56 to 224 tons) per day.

5.18.2 Process Description[1-2]

Hydrogen sulfide, a byproduct of crude oil and natural gas processing, is recovered and converted to elemental sulfur by the Claus process. Figure 5.18-1 shows a typical Claus sulfur recovery unit. The process consists of multistage catalytic oxidation of hydrogen sulfide according to the following overall reaction:

$$2H_2S + O_2 \rightarrow 2S + 2H_2O \quad (1)$$

Each catalytic stage consists of a gas reheater, a catalyst chamber and a condenser.

The Claus process involves burning one third of the hydrogen sulfide (H_2S) with air in a reactor furnace to form sulfur dioxide (SO_2) according to the following reaction:

$$2H_2S + 3O_2 \rightarrow 2SO_2 + 2H_2O + \text{heat} \quad (2)$$

The furnace normally operates at combustion chamber temperatures ranging from 980 to 1540°C (1800 to 2800°F) with pressures rarely higher than 70 kPa (10 psia). 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.

The remaining uncombusted two-thirds of the hydrogen sulfide undergoes Claus reaction (reacts with SO_2) to form elemental sulfur as follows:

$$2H_2S + SO_2 \leftrightarrow 3S + 2H_2O + \text{heat} \quad (3)$$

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. It is estimated that 95 to 97 percent overall recovery can be

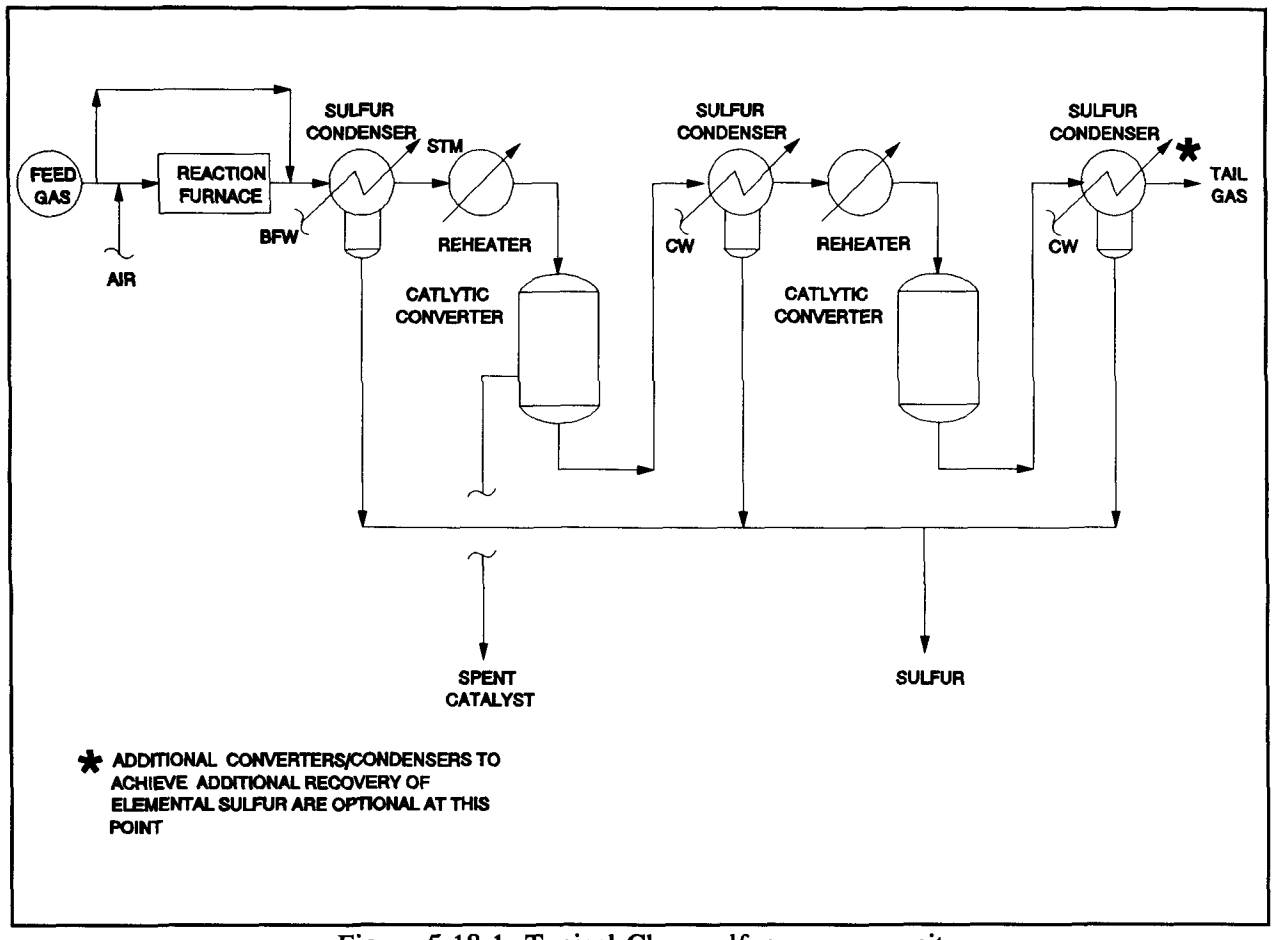


Figure 5.18-1 Typical Claus sulfur recovery unit

achieved depending on the number of catalytic reaction stages and the type of reheating method used. If the sulfur recovery unit is located in a natural gas processing plant, the type of reheat employed is typically either auxiliary burners or heat exchangers, with steam reheat being used occasionally. If the sulfur recovery unit is located in a crude oil refinery, the typical reheat scheme uses 3536 to 4223 kPa (500 to 600 psig) steam for reheating purposes. 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.

In addition to the oxidation of H_2S to SO_2 and the reaction of SO_2 with H_2S in the reaction furnace, many other side reactions can and do occur in the furnace. Several of these possible side reactions are:

$$CO_2 + H_2S \rightarrow COS + H_2O \quad (4)$$

$$COS + H_2S \rightarrow CS_2 + H_2O \quad (5)$$

$$2COS \rightarrow CO_2 + CS_2 \quad (6)$$

5.18.3 Emissions and Controls[1-4]

Table 5.18-1 shows emission factors and recovery efficiencies for modified Claus sulfur recovery plants. Emissions from the Claus process are directly related to the recovery efficiency. Higher recovery efficiencies mean less sulfur emitted in the tailgas. Older plants, or very small Claus plants producing less than 20 megagrams (22 tons) per day of sulfur without tailgas cleanup, have varying sulfur recovery efficiencies. The efficiency depends upon several factors, including the number of catalytic stages, the concentrations of H_2S and contaminants in the feed stream, stoichiometric balance of gaseous components of the inlet, operating temperature, and catalyst maintenance.

A two-bed catalytic Claus plant can achieve 94 to 96 percent efficiency. Recoveries range from 96 to 97.5 percent for a three-bed catalytic plant and range from 97 to 98.5 percent for a four-bed catalytic plant. At normal operating temperatures and pressures, the Claus reaction is thermodynamically limited to 97 to 98 percent recovery. Tailgas from the Claus plant still contains 0.8 to 1.5 percent sulfur compounds.

Existing new source performance standard (NSPS) limits sulfur emissions from Claus sulfur recovery plants of greater than 20.32 megagrams (22.40 ton) per day capacity to 0.025 percent (250 ppmv) by volume. This limitation is effective at zero percent oxygen on a dry basis if emissions are controlled by an oxidation control system or a reduction control system followed by incineration. This is comparable to the 99.8 to 99.9 percent control level for reduced sulfur.

Table 5.18-1 (Metric and English Units).
EMISSION FACTORS FOR MODIFIED CLAUS SULFUR RECOVERY PLANTS

Number of Catalytic Stages	Average Percent Sulfur Recovery[a]	SO_2 Emissions		
		kg/Mg of Sulfur Produced	lb/ton of Sulfur Produced	Emission Factor Rating
Two, uncontrolled	93.5[c]	139[b,c]	278[b,c]	E
Three, uncontrolled	95.5[d]	94[b,d]	188[b,d]	E
Four, uncontrolled	96.5[e]	73[b,e]	145[b,e]	E
Two, controlled[f]	98.6	29	57	B
Three, controlled[g]	96.8	65	129	B

[a] Efficiencies are for feedgas streams with high H_2S concentrations. Gases with lower H_2S concentrations would have lower efficiencies. For example, a 2- or 3-stage plant could have a recovery efficiency of 95% for a 90% H_2S stream, 93% for 50% H_2S, and 90% for 15% H_2S.

[b] Reference 5. Based on net weight of pure sulfur produced. The emission factors were determined using the average of the percentage recovery of sulfur. Sulfur dioxide emissions are calculated from percentage sulfur recovery by one of the following equations:

$$SO_2 \text{ emissions (kg/Mg)} = \frac{(100 - \%\text{recovery})}{\%\text{recovery}} \times 2000$$

$$SO_2 \text{ emissions (lb/ton)} = \frac{(100 - \%\text{recovery})}{\%\text{recovery}} \times 4000$$

[c] Typical sulfur recovery ranges from 92 to 95 percent.

[d] Typical sulfur recovery ranges from 95 to 96 percent.

[e] Typical sulfur recovery ranges from 96 to 97 percent.

[f] Reference 6. Test data indicated sulfur recovery ranges from 98.3 to 98.8 percent.

[g] References 7, 8 and 9. Test data indicated sulfur recovery ranges from 95 to 99.8 percent.

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.

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 sulfur dioxide (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 Wellman-Lord, Stauffer Aquaclaus and IFP-2. Only the Wellman-Lord process has been applied successfully to U.S. refineries.

The Wellman-Lord process uses a wet generative process to reduce stack gas sulfur dioxide concentration to less than 250 parts per million volume (ppmv) and can achieve approximately 99.9 percent sulfur recovery. Claus plant tailgas is incinerated and all sulfur species are oxidized to form sulfur dioxide (SO_2) in the Wellman-Lord process. Gases are then cooled and quenched to remove excess water and to reduce gas temperature to absorber conditions. The rich SO_2 gas is then reacted with a solution of sodium sulfite (Na_2SO_3) and sodium bisulfite ($NaHSO_3$) to form the bisulfite:

$$SO_2 + Na_2SO_3 + H_2O \rightarrow 2NaHSO_3 \quad (7)$$

The offgas is reheated and vented to the atmosphere. The resulting bisulfite solution is boiled in an evaporator-crystallizer, where it decomposes to SO_2 and H_2O vapor and sodium sulfite is precipitated:

$$2NaHSO_3 \rightarrow Na_2SO_3\downarrow + H_2O + SO_2\uparrow \quad (8)$$

Sulfite crystals are separated and redissolved for reuse as lean solution in the absorber. The wet SO_2 gas is directed to a partial condenser where most of the water is condensed and reused to dissolve sulfite crystals. The enriched SO_2 stream is then recycled back to the Claus plant for conversion to elemental sulfur.

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_2S-to-sulfur process (the Strefford process). The other three processes utilize conventional amine scrubbing and regeneration to remove H_2S an recycle back as Claus feed.

Emissions from the Claus process may also be reduced by incinerating sulfur-containing tailgases to form sulfur dioxide. In order to properly remove the sulfur, incinerators must operate at a temperature of 650°C (1,200°F) or higher if all the H_2S is to be combusted. Proper air-to-fuel ratios are needed to eliminate pluming from the incinerator stack. The stack should be equipped with analyzers to monitor the SO_2 level.

References for Section 5.18

1. B. Goar *et al.*, "Sulfur Recovery Technology," *Energy Progress*, Vol. 6(2): 71-75, June, 1986.

2. Written communication from Bruce Scott, Bruce Scott, Inc. to David Hendricks, Pacific Environmental Services, Inc., February 28, 1992.

3. *Review of New Source Performance Standards for Petroleum Refinery Claus Sulfur Recovery Plants*, EPA-450/3-83-014, U. S. Environmental Protection Agency, Research Triangle Park, NC, August 1983.

4. *Standards Support and Environmental Impact Statement, Volume 1: Proposed Standards of Performance for Petroleum Refinery Sulfur Recovery Plants*. EPA-450/2-76-016a, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1976.

5. D. K. Beavon, "Abating Sulfur Plant Gases," *Pollution Engineering*, January/February 1972, pp. 34-35.

6. "Compliance Test Report: Collett Ventures Company, Chatom, Alabama," Environmental Science & Engineering, Inc., Gainesville, FL, May 1991.

7. "Compliance Test Report: Phillips Petroleum Company, Chatom, Alabama," Environmental Science & Engineering, Inc., Gainesville, FL, July 1991.

8. "Compliance Test report: Mobil Exploration and Producing Southeast, Inc., Coden, Alabama," Cubix Corporation, Austin, TX, September 1990.

9. "Emission Test Report: Getty Oil Company, New Hope, TX," EMB Report No. 81-OSP-9, July 1981.

6.8 AMMONIUM NITRATE

6.8.1 General[1-3]

Ammonium nitrate (NH_4NO_3) is produced by neutralizing nitric acid (HNO_3) with ammonia (NH_3). In 1991, there were 58 U.S. ammonium nitrate plants located in 22 states producing about 8.2 million megagrams (nine million tons) of ammonium nitrate. Approximately 15 to 20 percent of this amount was used for explosives and the balance for fertilizer.

Ammonium nitrate is marketed in several forms, depending upon its use. Liquid ammonium nitrate may be sold as a fertilizer, generally in combination with urea. Liquid ammonium nitrate may be concentrated to form an ammonium nitrate "melt" for use in solids formation processes. Solid ammonium nitrate may be produced in the form of prills, grains, granules or crystals. Prills can be produced in either high or low density form, depending on the concentration of the melt. High density prills, granules and crystals are used as fertilizer, grains are used solely in explosives, and low density prills can be used as either.

6.8.2 Process Description[1,2]

The manufacture of ammonium nitrate involves several major unit operations including solution formation and concentration; solids formation, finishing, screening and coating; and product bagging and/or bulk shipping. In some cases, solutions may be blended for marketing as liquid fertilizers. These operations are shown schematically in Figure 6.8-1.

The number of operating steps employed depends on the end product desired. For example, plants producing ammonium nitrate solutions alone use only the solution formation, solution blending and bulk shipping operations. Plants producing a solid ammonium nitrate product may employ all of the operations.

All ammonium nitrate plants produce an aqueous ammonium nitrate solution through the reaction of ammonia and nitric acid in a neutralizer as follows:

$$NH_3 + HNO_3 \rightarrow NH_4NO_3 \quad (1)$$

Approximately 60 percent of the ammonium nitrate produced in the U.S. is sold as a solid product. To produce a solid product, the ammonium nitrate solution is concentrated in an evaporator or concentrator. The resulting "melt" contains about 95 to 99.8 percent ammonium nitrate at approximately 149°C (300°F). This melt is then used to make solid ammonium nitrate products.

Prilling and granulation are the most common processes used to produce solid ammonium nitrate. To produce prills, concentrated melt is sprayed into the top of a prill tower. In the tower, ammonium nitrate droplets fall countercurrent to a rising air stream that cools and solidifies the falling droplets into spherical prills. Prill density can be varied by using different concentrations of ammonium nitrate melt. Low density prills, in the range of 1.29 specific gravity, are formed from a 95 to 97.5 percent ammonium nitrate melt, and high density prills, in the range of 1.65 specific

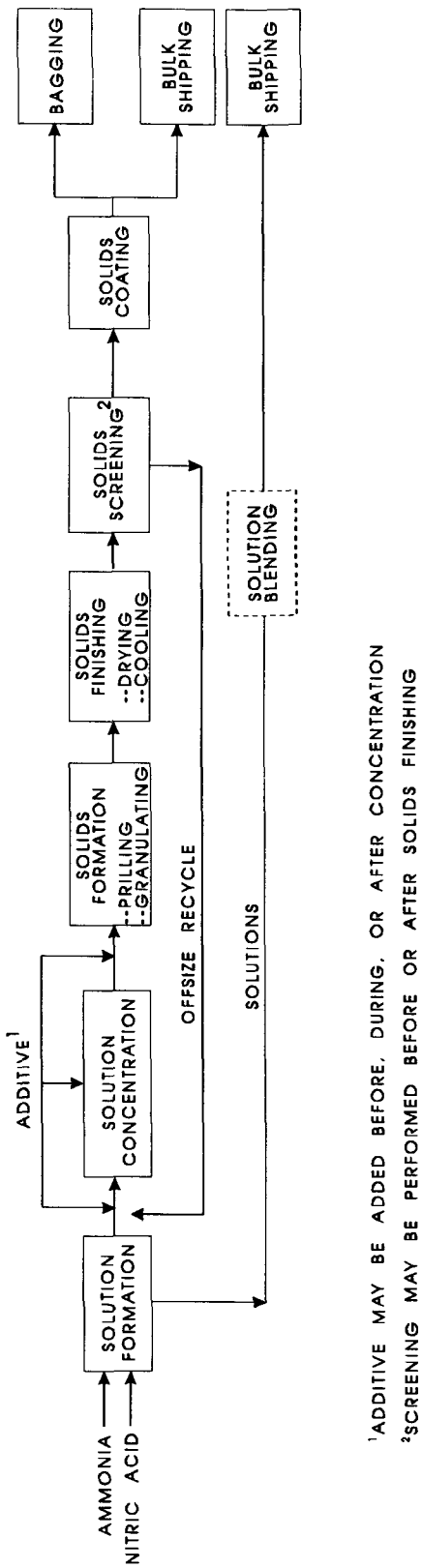


Figure 6.8-1 Ammonium nitrate manufacturing operations

gravity, are formed from a 99.5 to 99.8 percent melt. Low density prills are more porous than high density prills. Therefore, low density prills are used for making blasting agents because they will absorb oil. Most high density prills are used as fertilizers.

Rotary drum granulators produce granules by spraying a concentrated ammonium nitrate melt (99.0 to 99.8 percent) onto small seed particles of ammonium nitrate in a long rotating cylindrical drum. As the seed particles rotate in the drum, successive layers of ammonium nitrate are added to the particles, forming granules. Granules are removed from the granulator and screened. Offsize granules are crushed and recycled to the granulator to supply additional seed particles or are dissolved and returned to the solution process. Pan granulators operate on the same principle as drum granulators, except the solids are formed in a large, rotating circular pan. Pan granulators produce a solid product with physical characteristics similar to those of drum granules.

Although not widely used, an additive such as magnesium nitrate or magnesium oxide may be injected directly into the melt stream. This additive serves three purposes: to raise the crystalline transition temperature of the final solid product; to act as a desiccant, drawing water into the final product to reduce caking; and to allow solidification to occur at a low temperature by reducing the freezing point of molten ammonium nitrate.

The temperature of the ammonium nitrate product exiting the solids formation process is approximately 66 to 124°C (150 to 255°F). Rotary drum or fluidized bed cooling prevents deterioration and agglomeration of solids before storage and shipping. Low density prills have a high moisture content because of the lower melt concentration, and therefore require drying in rotary drums or fluidized beds before cooling.

Since the solids are produced in a wide variety of sizes, they must be screened for consistently sized prills or granules. Cooled prills are screened and offsize prills are dissolved and recycled to the solution concentration process. Granules are screened before cooling. Undersize particles are returned directly to the granulator and oversize granules may be either crushed and returned to the granulator or sent to the solution concentration process.

Following screening, products can be coated in a rotary drum to prevent agglomeration during storage and shipment. The most common coating materials are clays and diatomaceous earth. However, the use of additives in the ammonium nitrate melt before solidification, as described above, may preclude the use of coatings.

Solid ammonium nitrate is stored and shipped in either bulk or bags. Approximately ten percent of solid ammonium nitrate produced in the U.S. is bagged.

6.8.3 Emissions and Controls

Emissions from ammonium nitrate production plants are particulate matter (ammonium nitrate and coating materials), ammonia and nitric acid. Ammonia and nitric acid are emitted primarily from solution formation and granulators. Particulate matter (largely as ammonium nitrate) is emitted from most of the process operations and is the primary emission addressed here.

The emission sources in solution formation and concentration processes are neutralizers and evaporators, primarily emitting nitric acid and ammonia. The vapor stream off the top of the

neutralization reactor is primarily steam with some ammonia and NH_4NO_3 particulates present. Specific plant operating characteristics, however, make these emissions vary depending upon use of excess ammonia or acid in the neutralizer. Since the neutralization operation can dictate the quantity of these emissions, a range of emission factors is presented in Table 6.8-1. Particulate emissions from these operations tend to be smaller in size than those from solids production and handling processes and generally are recycled back to the process.

Emissions from solids formation processes are ammonium nitrate particulate matter and ammonia. The sources of primary importance are prill towers (for high density and low density prills) and granulators (rotary drum and pan). Emissions from prill towers result from carryover of fine particles and fume by the prill cooling air flowing through the tower. These fine particles are from microprill formation, attrition of prills colliding with the tower or one another, and from rapid transition of the ammonia nitrate between crystal states. The uncontrolled particulate emissions from prill towers, therefore, are affected by tower airflow, spray melt temperature, condition and type of melt spray device, air temperature, and crystal state changes of the solid prills. The amount of microprill mass that can be entrained in the prill tower exhaust is determined by the tower air velocity. Increasing spray melt temperature causes an increase in the amount of gas phase ammonium nitrate generated. Thus, gaseous emissions from high density prilling are greater than from low density towers.

Table 6.8-1 (Metric Units)
EMISSION FACTORS FOR PROCESSES IN
AMMONIUM NITRATE MANUFACTURING PLANTS[a]

Process	Particulate Matter				Ammonia Uncontrolled[c]		Nitric Acid	
	Uncontrolled		Controlled[b]					
	kg/Mg of Product	Factor Rating	kg/Mg of Product	Factor Rating	kg/Mg of Product	Factor Rating	kg/Mg of Product	Factor Rating
Neutralizer	0.045-4.3	B	0.002-0.22	B	0.43-18.0	B	0.042-1[d]	B
Evaporation/concentration operations	0.26	A			0.27-16.7	A		
Solids Formation Operations								
High density prill towers	1.59	A	0.60	A	28.6	A		
Low density prill towers	0.46	A	0.26	A	0.13	A		
Rotary drum granulators	146	A	0.22	A	29.7	A		
Pan granulators	1.34	A	0.02	A	0.07	A		
Coolers and dryers								
High density prill coolers[e]	0.8	A	0.01	A	0.02	A		
Low density prill coolers[e]	25.8	A	0.26	A	0.15	A		
Low density prill dryers[e]	57.2	A	0.57	A	0-1.59	A		
Rotary drum granulator coolers[e]	8.1	A	0.08	A				
Pan granulator coolers[e]	18.3	A	0.18	B				
Coating operations[f]	≤ 2.0	B	≤ 0.02	B				
Bulk loading operations[f]	≤ 0.01	B						

[a]Some ammonium nitrate emission factors are based on data gathered using a modification of EPA Method 5 (See Reference 1).

[b]Based on the following control efficiencies for wet scrubbers, applied to uncontrolled emissions: neutralizers, 95 percent; high density prill towers, 62 percent; low density prill towers, 43 percent; rotary drum granulators, 99.9 percent; pan granulators, 98.5 percent; coolers, dryers, and coaters, 99%.

[c]Given as ranges because of variation in data and plant operations. Factors for controlled emissions not presented due to conflicting results on control efficiency.

[d]Based on 95 percent recovery in a granulator recycle scrubber.

[e]Factors for coolers represent combined precooler and cooler emissions, and factors for dryers represent combined predryer and dryer emissions.

[f]Fugitive particulate emissions arise from coating and bulk loading operations.

TABLE 6.8-1 (ENGLISH UNITS)
EMISSION FACTORS FOR PROCESSES IN
AMMONIUM NITRATE MANUFACTURING PLANTS[a]
All Emission Factors are in
Ratings (A-E) Follow Each Factor

Process	Particulate Matter				Ammonia		Nitric Acid	
	Uncontrolled		Controlled[b]		Uncontrolled[c]			
	lb/ton of Product	Factor Rating	lb/ton of Product	Factor Rating	lb/ton of Product	Factor Rating	lb/ton of Product	Factor Rating
Neutralizer	0.09-8.6	B	0.004-0.43	B	0.86-36.0	B	0.084-2[d]	B
Evaporation/concentration operations	0.52	A			0.54-33.4	A		
Solids Formation Operations								
High density prill towers	3.18	A	1.20	A	57.2	A		
Low density prill towers	0.92	A	0.52	A	0.26	A		
Rotary drum granulators	392	A	0.44	A	59.4	A		
Pan granulators	2.68	A	0.04	A	0.14	A		
Coolers and dryers								
High density prill coolers[e]	1.6	A	0.02	A	0.04	A		
Low density prill coolers[e]	51.6	A	0.52	A	0.30	A		
Low density prill dryers[e]	114.4	A	1.14	A	0-3.18	A		
Rotary drum granulator coolers[e]	16.2	A	0.16	A				
Pan granulator coolers[e]	36.6	A	0.36	B				
Coating operations[f]	≤ 4.0	B	≤ 0.04	B				
Bulk loading operations[f]	≤ 0.02	B						

[a]Some ammonium nitrate emission factors are based on data gathered using a modification of EPA Method 5 (See Reference 1).

[b]Based on the following control efficiencies for wet scrubbers, applied to uncontrolled emissions: neutralizers, 95 percent; high density prill towers, 62 percent; low density prill towers, 43 percent; rotary drum granulators, 99.9 percent; pan granulators, 98.5 percent; coolers, dryers, and coaters, 99%.

[c]Given as ranges because of variation in data and plant operations. Factors for controlled emissions not presented due to conflicting results on control efficiency.

[d]Based on 95 percent recovery in a granulator recycle scrubber.

[e]Factors for coolers represent combined precooler and cooler emissions, and factors for dryers represent combined predryer and dryer emissions.

[f]Fugitive particulate emissions arise from coating and bulk loading operations.

Microprill formation resulting from partially plugged orifices of melt spray devices can increase fine dust loading and emissions. Certain designs (spinning buckets) and practices (vibration of spray plates) help reduce microprill formation. High ambient air temperatures can cause increased emissions because of entrainment as a result of higher air flow required to cool prills and because of increased fume formation at the higher temperatures.

The granulation process in general provides a larger degree of control in product formation than does prilling. Granulation produces a solid ammonium nitrate product that, relative to prills, is larger and has greater abrasion resistance and crushing strength. The air flow in granulation processes is lower than that in prilling operations. Granulators, however, cannot produce low density ammonium nitrate economically with current technology. The design and operating parameters of granulators may affect emission rates. For example, the recycle rate of seed ammonium nitrate particles affects the bed temperature in the granulator. An increase in bed temperature resulting from decreased recycle of seed particles may cause an increase in dust emissions from granule disintegration.

Cooling and drying are usually conducted in rotary drums. As with granulators, the design and operating parameters of the rotary drums may affect the quantity of emissions. In addition to design parameters, prill and granule temperature control is necessary to control emissions from disintegration of solids caused by changes in crystal state.

Emissions from screening operations are generated by the attrition of the ammonium nitrate solids against the screens and against one another. Almost all screening operations used in the ammonium nitrate manufacturing industry are enclosed or have a cover over the uppermost screen. Screening equipment is located inside a building and emissions are ducted from the process for recovery or reuse.

Prills and granules are typically coated in a rotary drum. The rotating action produces a uniformly coated product. The mixing action also causes some of the coating material to be suspended, creating particulate emissions. Rotary drums used to coat solid product are typically kept at a slight negative pressure and emissions are vented to a particulate control device. Any dust captured is usually recycled to the coating storage bins.

Bagging and bulk loading operations are a source of particulate emissions. Dust is emitted from each type of bagging process during final filling when dust laden air is displaced from the bag by the ammonium nitrate. The potential for emissions during bagging is greater for coated than for uncoated material. It is expected that emissions from bagging operations are primarily the kaolin, talc or diatomaceous earth coating matter. About 90 percent of solid ammonium nitrate produced domestically is bulk loaded. While particulate emissions from bulk loading are not generally controlled, visible emissions are within typical state regulatory requirements (below 20 percent opacity).

Table 6.8-1 summarizes emission factors for various processes involved in the manufacture of ammonium nitrate. Uncontrolled emissions of particulate matter, ammonia and nitric acid are given in the Table. Emissions of ammonia and nitric acid depend upon specific operating practices, so ranges of factors are given for some emission sources.

Emission factors for controlled particulate emissions are also in Table 6.8-1, reflecting wet

scrubbing particulate control techniques. The particle size distribution data presented in Table 6.8-2 indicate the emissions. In addition, wet scrubbing is used as a control technique because the solution containing the recovered ammonium nitrate can be sent to the solution concentration process for reuse in production of ammonium nitrate, rather than to waste disposal facilities.

Table 6.8-2
PARTICLE SIZE DISTRIBUTION DATA FOR UNCONTROLLED EMISSIONS FROM AMMONIUM NITRATE MANUFACTURING FACILITIES[a]

Operation	Cumulative Weight %		
	≤ 2.5 μm	≤ 5 μm	≤ 10 μm
Solids Formation Operations			
Low density prill tower	56	73	83
Rotary drum granulator	0.07	0.3	2
Coolers and Dryers			
Low density prill cooler	0.03	0.09	0.4
Low density prill predryer	0.03	0.06	0.2
Low density prill dryer	0.04	0.04	0.15
Rotary drum granulator cooler	0.06	0.5	3
Pan granulator precooler	0.3	0.3	1.5

[a]References 5, 12, 13, 23 and 24. Particle size determinations were not done in strict accordance with EPA Method 5. A modification was used to handle the high concentrations of soluble nitrogenous compounds (See Reference 1). Particle size distributions were not determined for controlled particulate emissions.

References for Section 6.8

1. *Ammonium Nitrate Manufacturing Industry: Technical Document*, EPA-450/3-81-002, U.S. Environmental Protection Agency, Research Triangle Park, NC, January 1981.

2. W.J. Search and R.B. Reznik, *Source Assessment: Ammonium Nitrate Production*, EPA-600/2-77-107i, U.S. Environmental Protection Agency, Research Triangle Park, NC, September 1977.

3. North American Fertilizer Capacity Data, Tennessee Valley Authority, Muscle Shoals, AL, December, 1991.

4. Memo from C.D. Anderson, Radian Corporation, Durham, NC, to Ammonium Nitrate file, July 2, 1980.

5. D.P. Becvar, *et al.*, *Ammonium Nitrate Emission Test Report: Union Oil Company of California*, EMB-78-NHF-7, U.S. Environmental Protection Agency, Research Triangle Park, NC, October 1979.

6. K.P. Brockman, *Emission Tests for Particulates*, Cominco American, Beatrice, NE, 1974.

7. Written communication from S.V. Capone, GCA Corporation, Chapel Hill, NC, To E.A. Noble, U.S. Environmental Protection Agency, Research Triangle Park, NC, September 6, 1979.

8. Written communication from D.E. Cayard, Monsanto Agricultural Products Company, St. Louis, MO, to E.A. Noble, U.S. Environmental Protection Agency, Research Triangle Park, NC, December 4, 1978.

9. Written communication from D.E. Cayard, Monsanto Agricultural Products Company, St. Louis, MO, to E.A. Noble, U.S. Environmental Protection Agency, Research Triangle Park, NC, December 27, 1978.

10. Written communication from T.H. Davenport, Hercules Incorporated, Donora, PA, to D.R. Goodwin, U.S. Environmental Protection Agency, Research Triangle Park, NC, November 16, 1978.

11. R.N. Doster and D.J. Grove, *Source Sampling Report: Atlas Powder Company*, Entropy Environmentalists, Inc., Research Triangle Park, NC, August 1976.

12. M.D. Hansen, *et al.*, *Ammonium Nitrate Emission Test Report: Swift Chemical Company*, EMB-79-NHF-11, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 1980.

13. R.A. Kniskern, *et al.*, *Ammonium Nitrate Emission Test Report: Cominco American, Inc.*, Beatrice, NE, EMB-79-NHF-9, U.S. Environmental Protection Agency, Research Triangle Park, NC, April 1979.

14. Written communication from J.A. Lawrence, C.F. Industries, Long Grove, IL, to D.R. Goodwin, U.S. Environmental Protection Agency, Research Triangle Park, NC, December 15, 1978.

15. Written communication from F.D. McLauley, Hercules Incorporated, Louisiana, MO, to D.R. Goodwin, U.S. Environmental Protection Agency, Research Triangle Park, NC, October 31, 1978.

16. W.E. Misa, *Report of Source Test: Collier Carbon and Chemical Corporation (Union Oil)*, Test No. 5Z-78-3, Anaheim, CA, January 12, 1978.

17. Written communication from L. Musgrove, Georgia Department of Natural Resources,

Atlanta, GA, to R. Rader, Radian Corporation, Durham, NC, May 21, 1980.

18. Written communication from D.J. Patterson, Nitrogen Corporation, Cincinnati, OH, to E.A. Noble, U.S. Environmental Protection Agency, Research Triangle Park, NC, March 26, 1979.

19. Written communication from H. Schuyten, Chevron Chemical Company, San Francisco, CA, to D.R. Goodwin, U.S. Environmental Protection Agency, March 2, 1979.

20. *Emission Test Report: Phillips Chemical Company*, Texas Air Control Board, Austin, TX, 1975.

21. *Surveillance Report: Hawkeye Chemical Company*, U.S. Environmental Protection Agency, Research Triangle Park, NC, December 29, 1976.

22. W.A. Wade and R.W. Cass, *Ammonium Nitrate Emission Test Report: C.F. Industries*, EMB-79-NHF-10, U.S. Environmental Protection Agency, Research Triangle Park, NC, November 1979.

23. W.A. Wade, *et al.*, *Ammonium Nitrate Emission Test Report: Columbia Nitrogen Corporation*, EMB-80-NHF-16, U.S. Environmental Protection Agency, Research Triangle Park, NC, January, 1981.

24. York Research Corporation, *Ammonium Nitrate Emission Test Report: Nitrogen Corporation*, EMB-78-NHF-5, U.S. Environmental Protection Agency, Research Triangle Park, NC, May 1979.

6.10 PHOSPHATE FERTILIZERS

Phosphate fertilizers are classified into three groups of chemical compounds. Two of these groups are known as superphosphates and are defined by the percentage of phosphorous as P_2O_5. Normal superphoshate contains between 15 and 21 percent phosphorous as P_2O_5 wheras triple superphosphate contains over 40 percent phosphorous. The remaining group is Ammonium Phosphate ($NH_4H_2PO_4$).

6.10.1 NORMAL SUPERPHOSPHATES

6.10.1.1 General[1-3]

Normal superphosphate refers to fertilizer material containing 15 to 21 percent phosphorous as phosphorous pentoxide (P_2O_5). As defined by the Census Bureau, normal superphosphate contains not more than 22 percent of available P_2O_5. There are currently about eight fertilizer facilities producing normal superphosphates in the U.S. with an estimated total production of about 273,000 megagrams (300,000 tons) per year.

6.10.1.2 Process Description[1]

Normal superphosphates are prepared by reacting ground phosphate rock with 65 to 75 percent sulfuric acid. An important factor in the production of normal superphosphates is the amount of iron and aluminum in the phosphate rock. Aluminum (as Al_2O_3) and iron (as Fe_2O_3) above five percent imparts an extreme stickiness to the superphosphate and makes it difficult to handle.

The two general types of sulfuric acid used in superphosphate manufacture are virgin and spent acid. Virgin acid is produced from elemental sulfur, pyrites, and industrial gases and is relatively pure. Spent acid is a recycled waste product from various industries that use large quantities of sulfuric acid. Problems encountered with using spent acid include unusual color, unfamiliar odor, and toxicity.

A generalized flow diagram of normal superphosphate production is shown in Figure 6.10.1-1. Ground phosphate rock and acid are mixed in a reaction vessel, held in an enclosed area for about 30 minutes until the reaction is partially completed, and then transferred, using an enclosed conveyer known as the den, to a storage pile for curing (the completion of the reaction). Following curing, the product is most often used as a high-phosphate additive in the production of granular fertilizers. It can also be granulated for sale as granulated superphosphate or granular mixed fertilizer. To produce granulated normal superphosphate, cured superphosphate is fed through a clod breaker and sent to a rotary drum granulator where steam, water, and acid may be added to aid in granulation. Material is processed through a rotary drum granulator, a rotary dryer, a rotary cooler, and is then screened to specification. Finally, it is stored in bagged or bulk form prior to being sold.

6.10.1.3 Emissions and Controls[1-6]

Sources of emissions at a normal superphosphate plant include rock unloading and feeding, mixing operations (in the reactor), storage (in the curing building), and fertilizer handling operations. Rock unloading, handling and feeding generate particulate emissions of phosphate rock dust. The mixer, den and curing building emit gases in the form of silicon tetrafluoride (SiF_4), hydrogen fluoride (HF) and particulates composed of fluoride and phosphate material. Fertilizer handling operations release fertilizer dust. Emission factors for the production of normal superphosphate are presented in Table 6.10.1-1.

At a typical normal superphosphate plant, emissions from the rock unloading, handling and feeding operations are controlled by a baghouse. Baghouse cloth filters have reported efficiencies of

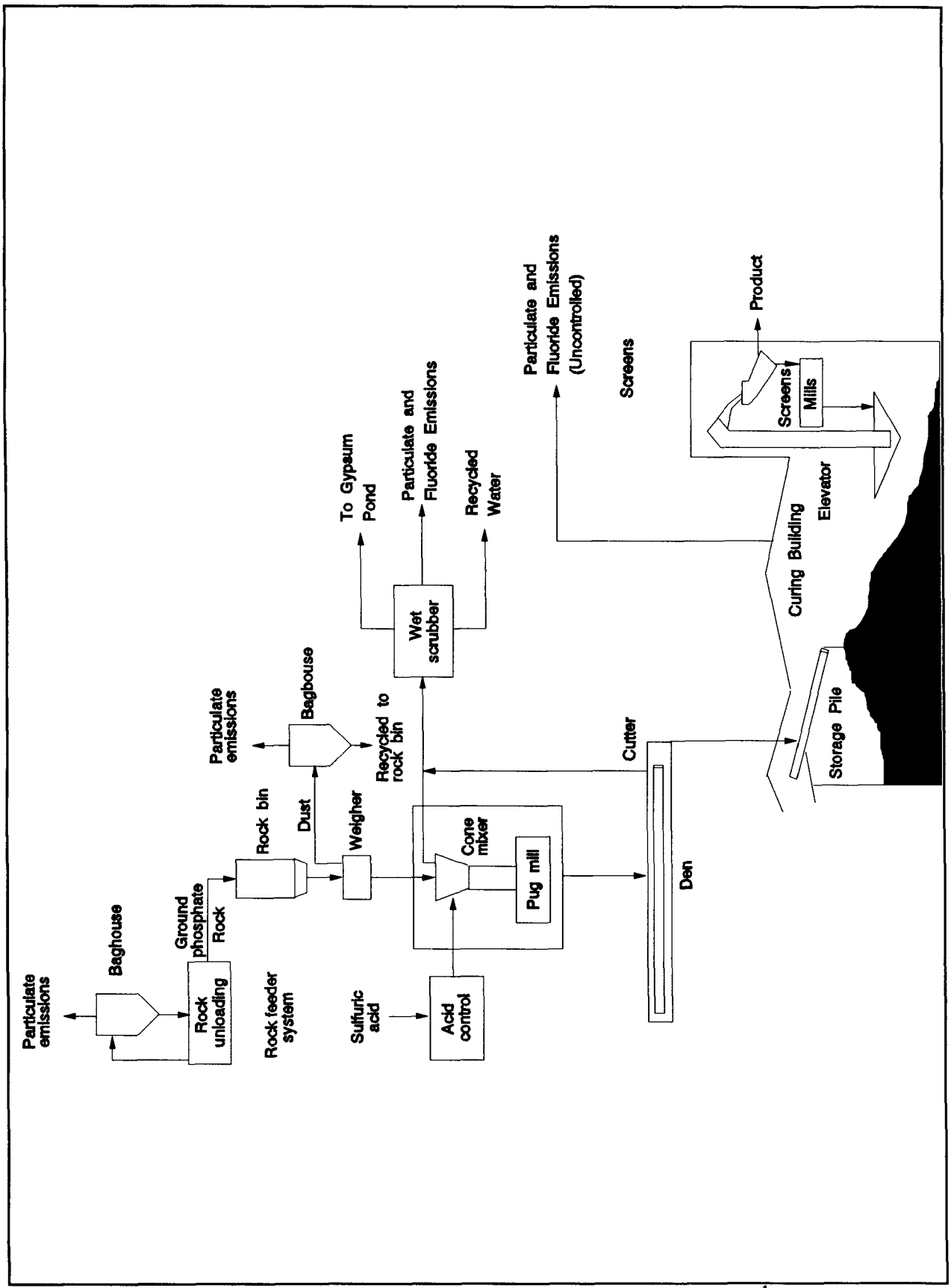


Figure 6.10.1-1 Normal superphosphate process flow diagram[1]

over 99 percent under ideal conditions. Collected dust is recycled. Emissions from the mixer and den are controlled by a wet scrubber. The curing building and fertilizer handling operations normally are not controlled.

Silicon tetrafluoride (SiF_4) and hydrogen fluoride (HF) emissions, and particulate from the mixer, den and curing building are controlled by scrubbing the offgases with recycled water. Gaseous silicon tetrafluoride in the presence of moisture reacts to form gelatinous silica, which has a tendency to plug scrubber packings. The use of conventional packed-countercurrent scrubbers and other contacting devices with small gas passages for emissions control is therefore limited. Scrubbers that can be used are cyclones, venturi, impingement, jet ejector and spray-crossflow packed scrubbers. Spray towers are also used as precontactors for fluorine removal at relatively high concentration levels of greater than 4.67 g/m^3 (3000 ppm).

Air pollution control techniques vary with particular plant designs. The effectiveness of abatement systems in removing fluoride and particulate also varies from plant to plant, depending on a number of factors. The effectiveness of fluorine abatement is determined by the inlet fluorine concentration, outlet or saturated gas temperature, composition and temperature of the scrubbing liquid, scrubber type and transfer units, and the effectiveness of entrainment separation. Control efficiency is enhanced by increasing the number of scrubbing stages in series and by using a fresh water scrub in the final stage. Reported efficiencies for fluoride control range from less than 90 percent to over 99 percent, depending on inlet fluoride concentrations and the system employed. An efficiency of 98 percent for particulate control is achievable.

The emission factors have not been adjusted by this revision, but they have been downgraded to an "E" quality rating based on the absence of supporting source tests. The PM-10 emission factors have been added to the table, but were taken from the AIRS Listing for Criteria Air Pollutants, which is also rated "E." No additional or recent data were found concerning fluoride emissions from gypsum ponds. A number of hazardous air pollutants (HAPs) have been identified by SPECIATE as being present in the phosphate manufacturing process. Some HAPs identified include hexane, methyl alcohol, formaldehyde, MEK, benzene, toluene, and styrene. Heavy metals such as lead and mercury are present in the phosphate rock. The phosphate rock is mildly radioactive due to the presence of some radionuclides. No emission factors are included for these HAPs, heavy metals, or radionuclides due to the lack of sufficient data.

Table 6.10.1-1. (Metric and English Units)
EMISSION FACTORS FOR THE PRODUCTION OF NORMAL SUPERPHOSPHATE

Emission point	Pollutant	Emission Factor		
		kg/Mg of P_2O_5 Produced	lb/ton of P_2O_5 Produced	Emission Factor Rating
Rock unloading[b]	Particulate	0.28	0.56	E[a]
	PM-10	0.15	0.29	E[e]
Rock feeding[b]	Particulate	0.06	0.11	E[a]
	PM-10	0.03	0.06	E[e]
Mixer and den[c]	Particulate	0.26	0.52	E[a]
	Fluoride	0.10	0.2	E[a]
	PM-10	0.22	0.44	E[e]
Curing building[d]	Particulate	3.60	7.20	E[a]
	Fluoride	1.90	3.80	E[a]
	PM-10	3.0	6.1	E[e]

[a]Reference 1, pp. 74-77, 169.
[b]Factors are for emissions from baghouse with an estimated collection efficiency of 99%.
[c]Factors are for emissions from wet scrubbers with a reported 97% control efficiency.
[d]Uncontrolled.
[e]Taken from AIRS Listing for Criteria Air Pollutants.

References for Section 6.10.1

1. J.M. Nyers, *et al.*, *Source Assessment: Phosphate Fertilizer Industry*, EPA-600/2-79-019c, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1979.

2. H.C. Mann, *Normal Superphosphate*, National Fertilizer & Environmental Research Center, Tennessee Valley Authority, Muscle Shoals, Alabama, February 1992.

3. North American Fertilizer Capacity Data (including supplement). Tennessee Valley Authority, Muscle Shoals, Alabama, December 1991.

4. Background Information for Standards of Performance: Phosphate Fertilizer Industry: Volume 1: Proposed Standards. EPA-450/2-74-019a, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1974.

5. Background Information for Standards of Performance: Phosphate Fertilizer Industry: Volume 2: Test Data Summary. EPA-450/2-74-019b, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1974.

6. Final Guideline Document: Control of Fluoride Emissions from Existing Phosphate Fertilizer Plants. EPA-450/2-77-005, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1977.

6.10.2 TRIPLE SUPERPHOSPHATES

6.10.2.1 General[2,3]

Triple superphosphate, also known as double, treble, or concentrated superphosphate, is a fertilizer material with a phosphorus content of over 40 percent, measured as phosphorus pentoxide (P_2O_5). Triple superphosphate is produced in only six fertilizer facilities in the U. S. In 1989, there were an estimated 3.2 million megagrams (3.5 million tons) of triple superphosphate produced. Production rates from the various facilities range from 23 to 92 megagrams (25 to 100 tons) per hour.

6.10.2.2 Process Description[1,2]

Two processes have been used to produce triple superphosphate: run-of-the-pile (ROP-TSP) and granular (GTSP). At this time, no facilities in the U. S. are currently producing ROP-TSP, but a process description is given.

The ROP-TSP material is essentially a pulverized mass of variable particle size produced in a manner similar to normal superphosphate. Wet-process phosphoric acid (50 to 55 percent P_2O_5) is reacted with ground phosphate rock in a cone mixer. The resultant slurry begins to solidify on a slow moving conveyer en route to the curing area. At the point of discharge from the den, the material passes through a rotary mechanical cutter that breaks up the solid mass. Coarse ROP-TSP product is sent to a storage pile and cured for three to five weeks. The product is then mined from the storage pile to be crushed, screened, and shipped in bulk.

Granular triple superphosphate yields larger, more uniform particles with improved storage and handling properties. Most of this material is made with the Dorr-Oliver slurry granulation process, illustrated in Figure 6.10.2-1. In this process, ground phosphate rock or limestone is reacted with phosphoric acid in one or two reactors in series. The phosphoric acid used in this process is appreciably lower in concentration (40 percent P_2O_5) than that used to manufacture ROP-TSP product. The lower strength acid maintains the slurry in a fluid state during a mixing period of one to two hours. A small sidestream of slurry is continuously removed and distributed onto dried, recycled fines, where it coats the granule surfaces and builds up its size.

Pugmills and rotating drum granulators have been used in the granulation process. Only one pugmill is currently operating in the U. S. A pugmill is composed of a u-shaped trough carrying twin counter-rotating shafts, upon which are mounted strong blades or paddles. The blades agitate, shear and knead the liquified mix and transport the material along the trough. The basic rotary drum granulator consists of an open-ended, slightly inclined rotary cylinder, with retaining rings at each end and a scraper or cutter mounted inside the drum shell. A rolling bed of dry material is maintained in the unit while the slurry is introduced through distributor pipes set lengthwise in the drum under the bed. Slurry-wetted granules are then discharged onto a rotary dryer, where excess water is evaporated and the chemical reaction is accelerated to completion by the dryer heat. Dried granules are then sized on vibrating screens. Oversize particles are crushed and recirculated to the screen, and undersize particles are recycled to the granulator. Product-size granules are cooled in a countercurrent rotary drum, then sent to a storage pile for curing. After a curing period of three to five days, granules are removed from storage, screened, bagged and shipped.

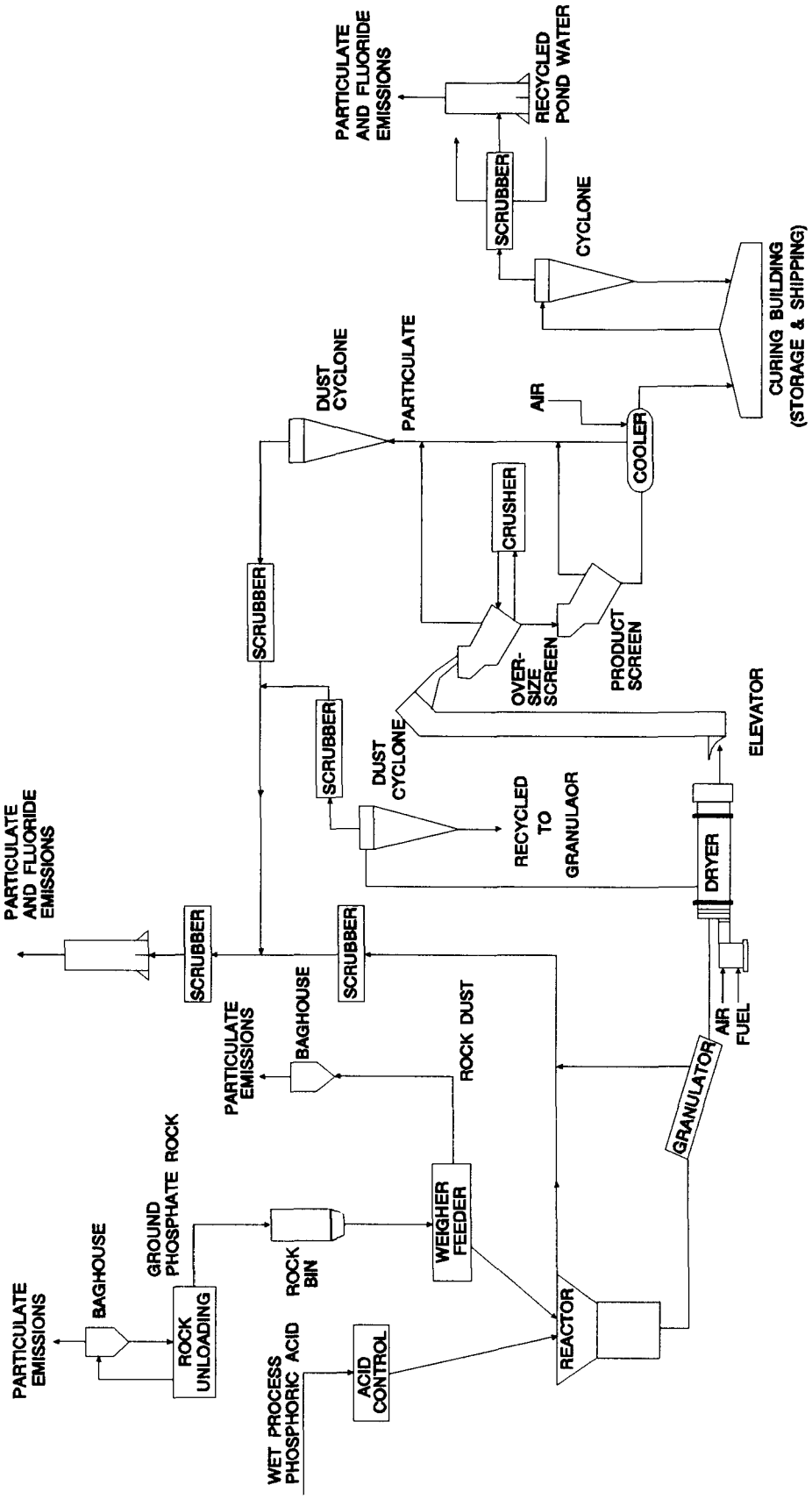


Figure 6.10.2-1. Dorr-Oliver process for granular triple superphosphate production[1]

6.10.2.3 Emissions and Controls[1-6]

Controlled emission factors for the production of GTSP are given in Table 6.10.2-1. Emission factors for ROP-TSP are not given since it is not being produced currently in the U. S.

Sources of particulate emissions include the reactor, granulator, dryer, screens, cooler, mills, and transfer conveyors. Additional emissions of particulate result from the unloading, grinding, storage, and transfer of ground phosphate rock. One facility uses limestone, which is received in granulated form and does not require additional milling.

TABLE 6.10.2-1 (METRIC UNITS)
CONTROLLED EMISSION FACTORS FOR THE PRODUCTION OF TRIPLE SUPERPHOSPHATES

Process	Pollutant	Controlled emission factor		
		kg/Mg of Product	lb/ton of Product	Emission Factor Rating
Granular triple superphosphate				
Rock unloading[b]	Particulate	0.09	0.18	E[a]
	PM-10	0.04	0.08	E[d]
Rock feeding[b]	Particulate	0.02	0.04	E[a]
	PM-10	0.01	0.02	E[d]
Reactor, granulator, dryer, cooler and screens[c]	Particulate	0.05	0.10	E[a]
	Fluoride	0.12	0.24	E[a]
	PM-10	0.04	0.08	E[d]
Curing building[c]	Particulate	0.10	0.20	E[a]
	Fluoride	0.02	0.04	E[a]
	PM-10	0.08	0.17	E[d]

[a]Reference 1, pp. 77-80, 168, 170-171.
[b]Factors are for emissions from baghouses with an estimated collection efficiency of 99 percent.
[c]Factors are for emissions from wet scrubbers with an estimated 97 percent control efficiency.
[d]Based on AIRS Listing For Criteria Air Pollutants.

Emissions of fluorine compounds and dust particles occur during the production of GTSP triple superphosphate. Silicon tetrafluoride (SiF_4) and hydrogen fluoride (HF) are released by the acidulation reaction and they evolve from the reactors, den, granulator, and dryer. Evolution of fluoride is essentially finished in the dryer and there is little fluoride evolved from the storage pile in the curing building.

At a typical plant, baghouses are used to control the fine rock particles generated by the rock grinding and handling activities. Emissions from the reactor, den and granulator are controlled by

scrubbing the effluent gas with recycled gypsum pond water in cyclonic scrubbers. Emissions from the dryer, cooler, screens, mills, product transfer systems, and storage building are sent to a cyclone separator for removal of a portion of the dust before going to wet scrubbers to remove fluorides.

Particulate emissions from ground rock unloading, storage and transfer systems are controlled by baghouse collectors. These baghouse cloth filters have reported efficiencies of over 99 percent. Collected solids are recycled to the process. Emissions of silicon tetrafluoride, hydrogen fluoride, and particulate from the production area and curing building are controlled by scrubbing the offgases with recycled water. Exhausts from the dryer, cooler, screens, mills, and curing building are sent first to a cyclone separator and then to a wet scrubber. Tailgas wet scrubbers perform final cleanup of the plant offgases.

Gaseous silicon tetrafluoride in the presence of moisture reacts to form gelatinous silica, which has the tendency to plug scrubber packings. Therefore, the use of conventional packed countercurrent scrubbers and other contacting devices with small gas passages for emissions control is not feasible. Scrubber types that can be used are 1) spray tower, 2) cyclone, 3) venturi, 4) impingement, 5) jet ejector, and 6) spray-crossflow packed.

The effectiveness of abatement systems for the removal of fluoride and particulate varies from plant to plant, depending on a number of factors. The effectiveness of fluorine abatement is determined by: 1) inlet fluorine concentration, 2) outlet or saturated gas temperature, 3) composition and temperature of the scrubbing liquid, 4) scrubber type and transfer units, and 5) effectiveness of entrainment separation. Control efficiency is enhanced by increasing the number of scrubbing stages in series and by using a fresh water scrub in the final stage. Reported efficiencies for fluoride control range from less than 90 percent to over 99 percent, depending on inlet fluoride concentrations and the system employed. An efficiency of 98 percent for particulate control is achievable.

The particulate and fluoride emission factors are identical to the previous revisions, but have been downgraded to "E" quality because no documented, up-to-date source tests were available and previous emission factors could not be validated from the references which were given. The PM-10 emission factors have been added to the table, but were derived from the AIRS Database, which also has an "E" rating. No additional or recent data were found concerning fluoride emissions from gypsum ponds. A number of hazardous air pollutants (HAPs) have been identified by SPECIATE as being present in the phosphate fertilizer manufacturing process. Some HAPs identified include hexane, methyl alcohol, formaldehyde, MEK, benzene, toluene, and styrene. Heavy metals such as lead and mercury are present in the phosphate rock. The phosphate rock is mildly radioactive due to the presence of some radionuclides. No emission factors are included for these HAPs, heavy metals, or radionuclides due to the lack of sufficient data.

References for Section 6.10.2

1. J. M. Nyers, *et al.*, *Source Assessment: Phosphate Fertilizer Industry*, EPA-600/2-79-019c, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1979.

2. H.C. Mann, *Triple Superphosphate*, National Fertilizer & Environmental Research Center, Tennessee Valley Authority, Muscle Shoals, Alabama, February 1992.

3. North American Fertilizer Capacity Data (including supplement). Tennesee Valley Authority, Muscle Shoals, Alabama, December 1991.

4. Background Information for Standards of Performance: Phosphate Fertilizer Industry: Volume 1: Proposed Standards. EPA-450/2-74-019a, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1974.

5. Background Information for Standards of Performance: Phosphate Fertilizer Industry: Volume 2: Test Data Summary. EPA-450/2-74-019b, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1974.

6. Final Guideline Document: Control of Fluoride Emissions from Existing Phosphate Fertilizer Plants. EPA-450/2-77-005, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1977.

6.10.3 AMMONIUM PHOSPHATE

6.10.3.1 General[1]

Ammonium phosphate ($NH_4H_2PO_4$) is produced by reacting phosphoric acid (H_3PO_4) with anhydrous ammonia (NH_3). Ammoniated superphosphates are produced by adding normal superphosphate or triple superphosphate to the mixture. The production of liquid ammonium phosphate and ammoniated superphosphates in fertilizer mixing plants is considered a separate process. Both solid and liquid ammonium phosphate fertilizers are produced in the U.S. This discussion covers only the granulation of phosphoric acid with anhydrous ammonia to produce granular fertilizer. Total ammonium phosphate production in the U.S. in 1992 was estimatd to be 7.7 million megagrams (8.5 million tons).[2]

6.10.3.2 Process Description[1]

Two basic mixer designs are used by ammoniation-granulation plants: the pugmill ammoniator and the rotary drum ammoniator. Approximately 95 percent of ammoniation-granulation plants in the United States use a rotary drum mixer developed and patented by the Tennessee Valley Authority (TVA). The basic rotary drum ammoniator-granulator consists of a slightly inclined open-end rotary cylinder with retaining rings at each end, and a scrapper or cutter mounted inside the drum shell. A rolling bed of recycled solids is maintained in the unit.

Ammonia-rich offgases pass through a wet scrubber before exhausting to the atmosphere. Primary scrubbers use raw materials mixed with acids (such as scrubbing liquor), and secondary scrubbers use gypsum pond water.

In the TVA process, phosphoric acid is mixed in an acid surge tank with 93 percent sulfuric acid (H_2SO_4), which is used for product analysis control, and with recycled acid from wet scrubbers. (A schematic diagram of the ammonium phosphate process flow diagram is shown in Figure 6.10.3-1.) Mixed acids are then partially neutralized with liquid or gaseous anhydrous ammonia in a brick-lined acid reactor. All of the phosphoric acid and approximately 70 percent of the ammonia are introduced into this vessel. A slurry of ammonium phosphate and 22 percent water are produced and sent through steam-traced lines to the ammoniator-granulator. Slurry from the reactor is distributed on the bed, the remaining ammonia (approximately 30 percent) is sparged underneath. Granulation, by agglomeration and by coating particulate with slurry, takes place in the rotating drum and is completed in the dryer. Ammonia-rich offgases pass through a wet scrubber before exhausting to the atmosphere. Primary scrubbers use raw materials mixed with acid (such as scrubbing liquor), and secondary scrubbers use pond water.

Moist ammonium phosphate granules are transferred to a rotary concurrent dryer and then to a cooler. Before being exhausted to the atmosphere, these offgases pass through cyclones and wet scrubbers. Cooled granules pass to a double-deck screen, in which oversize and undersize particles are separated from product particles. The product ranges in granule size from 1 to 4 millimeters (mm). The oversized granules are crushed, mixed with the undersized, and recycled back to the ammoniator-granulator.

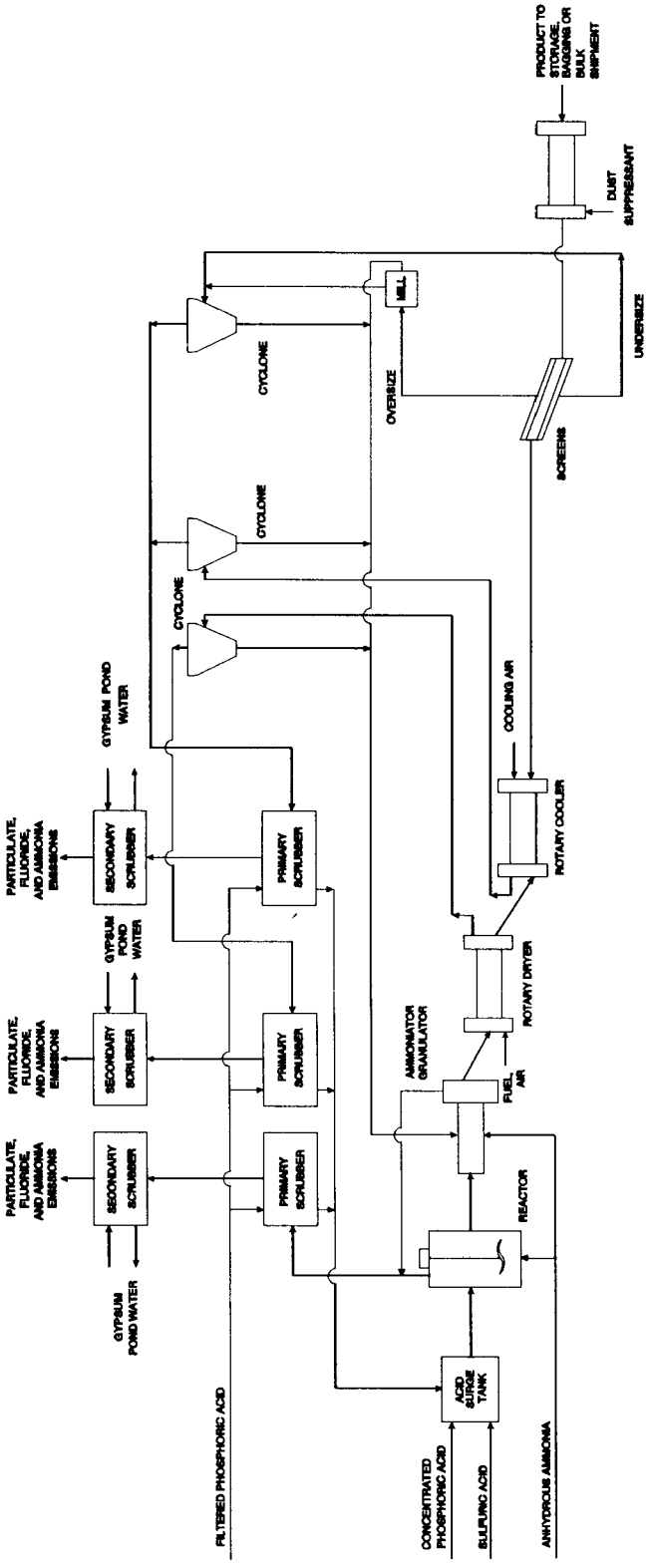


Figure 6.10.3-1. Ammonium phosphate process flow diagram

6.10.3.3 Emissions and Controls[1]

Sources of air emissions from the production of ammonium phosphate fertilizers include the reactor, the ammoniator-granulator, the dryer and cooler, product sizing and material transfer, and the gypsum pond. The reactor and ammoniator-granulator produce emissions of gaseous ammonia, gaseous fluorides such as hydrogen fluoride (HF) and silicon tetrafluoride (SiF_4), and particulate ammonium phosphates. These two exhaust streams are generally combined and passed through primary and secondary scrubbers.

Exhaust gases from the dryer and cooler also contain ammonia, fluorides and particulates and these streams are commonly combined and passed through cyclones and primary and secondary scrubbers. Particulate emissions and low levels of ammonia and fluorides from product sizing and material transfer operations are controlled the same way.

Emissions factors for ammonium phosphate production are summarized in Table 6.10.3-1. These emission factors are averaged based on recent source test data from controlled phosphate fertilizer plants in Tampa, Florida.

Table 6.10.3-1. (Metric Units)
AVERAGE CONTROLLED EMISSION FACTORS FOR THE PRODUCTION OF AMMONIUM PHOSPHATES[a]

Emission Point	Fluoride as F		Particulate		Ammonia		SO_2	
	kg/Mg of Product	Factor Rating	kg/Mg of Product	Factor Rating	kg/Mg of Product	Factor Rating	kg/Mg of Product	Factor Rating
Reactor/ammoniator-granulator	0.02	E	0.76	E				
Dryer/cooler	0.02	E	0.75	E				
Product sizing and material transfer[b]	0.001	E	0.03	E				
Total plant emissions	0.02[c]	A	0.34[d]	A	0.07	E	0.04[e]	E

[a] Reference 1, pp. 80-83, 173
[b] Represents only one sample.
[c] References 7, 8, 10, 11, 13-15. EPA has promulgated a fluoride emission guideline of 0.03 kg/Mg P_2O_5 input.
[d] References 7, 9, 10, 13-15.
[e] Based on limited data from only one plant, Reference 9.

Table 6.10.3-1. (English Units)
AVERAGE CONTROLLED EMISSION FACTORS FOR
THE PRODUCTION OF AMMONIUM PHOSPHATES[a]

Emission Point	Fluoride as F		Particulate		Ammonia		SO_2	
	lb/ton of Product	Factor Rating	lb/ton of Product	Factor Rating	lb/ton of Product	Factor Rating	lb/ton of Product	Factor Rating
Reactor/ammoniator-granulator	0.05	E	1.52	E				
Dryer/cooler	0.04	E	1.50	E				
Product sizing and material transfer[b]	0.002	E	0.06	E				
Total plant emissions	0.04[c]	A	0.68[d]	A	0.14	E	0.08[e]	E

[a] Reference 1, pp. 80-83, 173
[b] Represents only one sample.
[c] References 7, 8, 10, 11, 13-15. EPA has promulgated a fluoride emission guideline of 0.03 kg/Mg P_2O_5 input.
[d] References 7, 9, 10, 13-15.
[e] Based on limited data from only one plant, Reference 9.

Exhaust streams from the reactor and ammoniator-granulator pass through a primary scrubber, in which phosphoric acid is used to recover ammonia and particulate. Exhaust gases from the dryer, cooler and screen first go to cyclones for particulate recovery, and then to primary scrubbers. Materials collected in the cyclone and primary scrubbers are returned to the process. The exhaust is sent to secondary scrubbers, where recycled gypsum pond water is used as a scrubbing liquid to control fluoride emissions. The scrubber effluent is returned to the gypsum pond.

Primary scrubbing equipment commonly includes venturi and cyclonic spray towers. Impingement scrubbers and spray-crossflow packed bed scrubbers are used as secondary controls. Primary scrubbers generally use phosphoric acid of 20 to 30 percent as scrubbing liquor, principally to recover ammonia. Secondary scrubbers generally use gypsum and pond water for fluoride control.

Throughout the industry, however, there are many combinations and variations. Some plants use reactor-feed concentration phosphoric acid (40 percent P_2O_5) in both primary and secondary scrubbers, and some use phosphoric acid near the dilute end of the 20 to 30 percent P_2O_5 range in only a single scrubber. Existing plants are equipped with ammonia recovery scrubbers on the reactor, ammoniator-granulator and dryer, and particulate controls on the dryer and cooler. Additional scrubbers for fluoride removal exist, but they are not typical. Only 15 to 20 percent of installations contacted in an EPA survey were equipped with spray-crossflow packed bed scrubbers or their equivalent for fluoride removal.

Emission control efficiencies for ammonium phosphate plant control equipment are reported as 94 to 99 percent for ammonium, 75 to 99.8 percent for particulates, and 74 to 94 percent for fluorides.

References for Section 6.10.3

1. J.M. Nyers, *et al.*, *Source Assessment: Phosphate Fertilizer Industry*, EPA-600/2-79-019c, U.S. Environmental Protection Agency, Research Triangle Park, NC, May 1979.

2. North American Fertilizer Capacity Data, Tennessee Valley Authority, Muscle Shoals, AL, December 1991.

3. *Compliance Source Test Report: Texasgulf Inc., Granular Triple Super Phosphate Plant*, Aurora, NC, May 1987.

4. *Compliance Source Test Report: Texasgulf Inc., Diammonium Phosphate Plant No.2*, Aurora, NC, August 1989.

5. *Compliance Source Test Report: Texasgulf Inc., Diammonium Phosphate Plant #2*, Aurora, NC, December 1991.

6. *Compliance Test Report: Texasgulf, Inc., Diammonium Phosphate #1*, Aurora, NC, September 1990.

7. *Compliance Source Test Report: Texasgulf Inc., Ammonium Phosphate Plant #2*, Aurora, NC, November 1990.

8. *Compliance Source Test Report: Texasgulf Inc., Diammonium Phosphate Plant #2*, Aurora, NC, November 1991.

9. *Compliance Source Test Report: IMC Fertilizer, Inc., #1 DAP plant*, Western Polk County, FL, October 1991.

10. *Compliance Source Test Report: IMC Fertilizer, Inc., #2 DAP Plant*, Western Polk County, FL, June 1991.

11. *Compliance Source Test Report: IMC Fertilizer, Inc.*, Western Polk County, FL, April 1991.

6.14 UREA

6.14.1 General[1,14]

Urea [$CO(NH_2)_2$], also known as carbamide or carbonyl diamide, is marketed as a solution or in solid form. Most urea solution produced is used in fertilizer mixtures, with a small amount going to animal feed supplements. Most solids are produced as prills or granules, for use as fertilizer or protein supplement in animal feed, and in plastics manufacturing. Five U.S. plants produce solid urea in crystalline form. About 7.3 million megagrams (8 million tons) of urea were produced in the U.S. in 1991. About 85 percent was used in fertilizers (both solid and solution forms), 3 percent in animal feed supplements and the remaining 12 percent in plastics and other uses.

6.14.2 Process Description[1,2]

The process for manufacturing urea involves a combination of up to seven major unit operations. These operations, illustrated by the flow diagram in Figure 6.14-1, are solution synthesis, solution concentration, solids formation, solids cooling, solids screening, solids coating and bagging and/or bulk shipping.

The combination of processing steps is determined by the desired end products. For example, plants producing urea solution use only the solution formulation and bulk shipping operations. Facilities producing solid urea employ these two operations and various combinations of the remaining five operations, depending upon the specific end product being produced.

In the solution synthesis operation, ammonia (NH_3) and carbon dioxide (CO_2) are reacted to form ammonium carbamate ($NH_2CO_2NH_4$). Typical operating conditions include temperatures from 180 to 20°C (356 to 392°F), pressures from 140 to 250 atm, NH_3:CO_2 molar ratios from 3:1 to 4:1, and a retention time of 20 to 30 minutes. The carbamate is then dehydrated to yield 70 to 77 percent aqueous urea solution. These reactions are as follows:

$$2NH_3 + CO_2 \rightarrow NH_2CO_2NH_4 \quad (1)$$

$$NH_2CO_2NH_4 \rightarrow NH_2CONH_2 + H_2O \quad (2)$$

The urea solution can be used as an ingredient of nitrogen solution fertilizers, or it can be concentrated further to produce solid urea.

The three methods of concentrating the urea solution are vacuum concentration, crystallization and atmospheric evaporation. The method chosen depends upon the level of biuret ($NH_2CONHCONH_2$) impurity allowable in the end product. Aqueous urea solution begins to decompose at 60°C (140°F) to biuret and ammonia. The most common method of solution concentration is evaporation.

The concentration process furnishes urea "melt" for solids formation. Urea solids are produced from the urea melt by two basic methods: prilling and granulation. Prilling is a process by which solid particles are produced from molten urea. Molten urea is sprayed from the top of a prill tower. As the droplets fall through a countercurrent air flow, they cool and solidify into nearly spherical particles. There are two types of prill towers, fluidized bed and nonfluidized bed. The major difference is that a separate solids cooling operation may be required to produce agricultural grade prills in a nonfluidized bed prill tower.

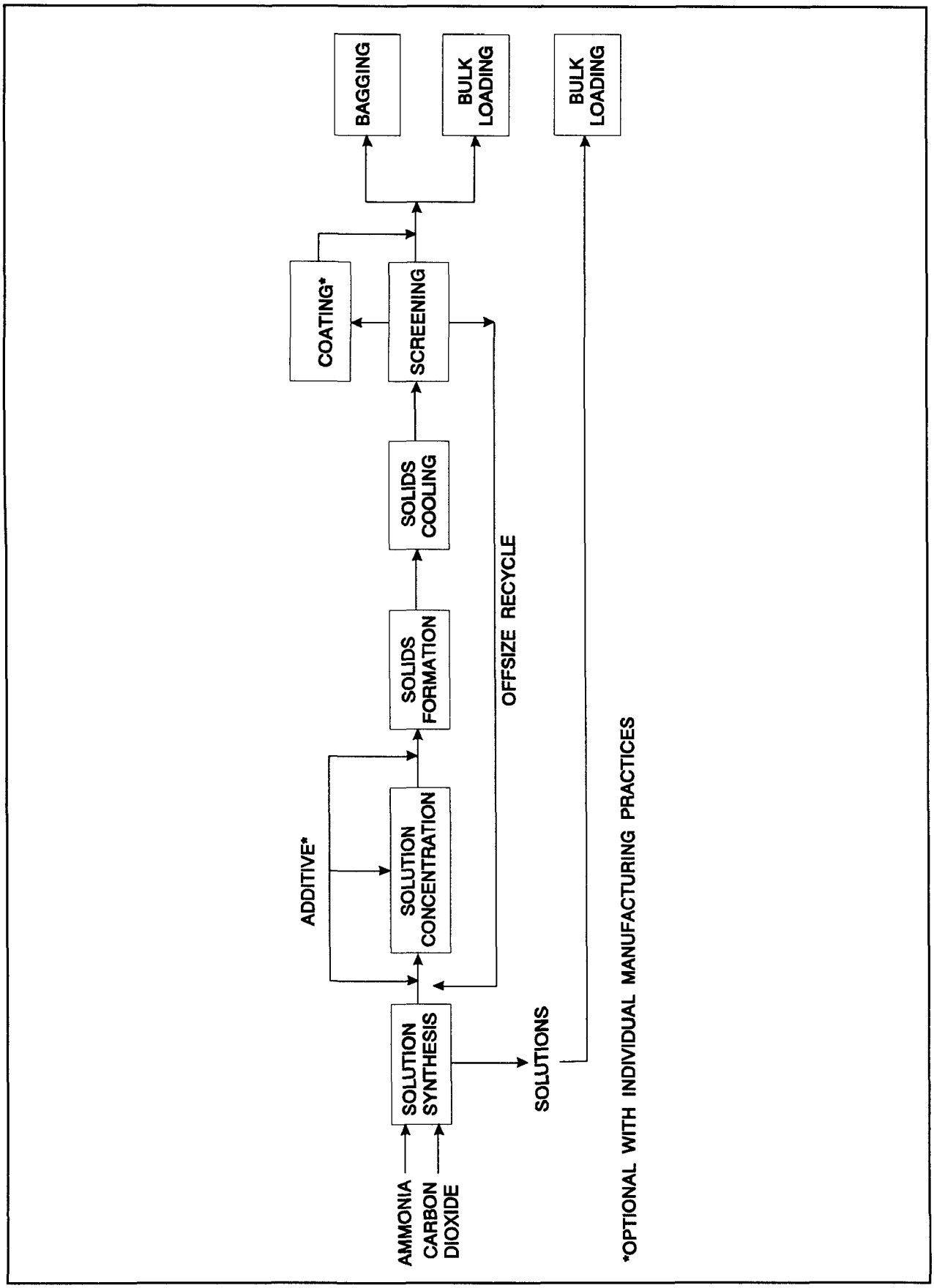


Figure 6.14-1 Major urea manufacturing operations

Granulation is used more frequently than prilling in producing solid urea for fertilizer. Granular urea is generally stronger than prilled urea, both in crushing strength and abrasion resistance. There are two granulation methods, drum granulation and pan granulation. In drum granulation, solids are built up in layers on seed granules placed in a rotating drum granulator/cooler approximately 4.3 meters (14 feet) in diameter. Pan granulators also form the product in a layering process, but different equipment is used and pan granulators are not commonly used in the U.S.

The solids cooling operation is generally accomplished during solids formation, but for pan granulation processes and for some agricultural grade prills, some supplementary cooling is provided by auxiliary rotary drums.

The solids screening operation removes offsize product from solid urea. The offsize material may be returned to the process in the solid phase or be redissolved in water and returned to the solution concentration process.

Clay coatings are used in the urea industry to reduce product caking and urea dust formation. The coating also reduces the nitrogen content of the product. The use of clay coating has diminished considerably, being replaced by injection of formaldehyde additives into the liquid or molten urea before solids formation. Formaldehyde reacts with urea to from methylenediurea, which is the conditioning agent. Additives reduce solids caking during storage and urea dust formation during transport and handling.

The majority of solid urea product is bulk shipped in trucks, enclosed railroad cars or barges, but approximately ten percent is bagged.

6.14.3 Emissions and Controls[1,3-7]

Emissions from urea manufacture are mainly ammonia and particulate matter. Formaldehyde and methanol, hazardous air pollutants (HAPs) may be emitted if additives are used. Formalin™, used as a formaldehyde additive, may contain up to 15 percent methanol. Ammonia is emitted during the solution synthesis and solids production processes. Particulate matter is emitted during all urea processes. There have been no reliable measurements of free gaseous formaldehyde emissions. The chromotropic acid procedure that has been used to measure formaldehyde is not capable of distinguishing between gaseous formaldehyde and methylenediurea, the principle compound formed when the formaldehyde additive reacts with hot urea.

Table 6.14-1 summarizes the uncontrolled and controlled emission factors, by processes, for urea manufacture. Table 6.14-2 summarizes particle sizes for these emissions.

In the synthesis process, some emission control is inherent in the recycle process where carbamate gases and/or liquids are recovered and recycled. Typical emission sources from the solution synthesis process are noncondensable vent streams from ammonium carbamate decomposers and separators. Emissions from synthesis processes are generally combined with emissions from the solution concentration process and are vented through a common stack. Combined particulate emissions from urea synthesis and concentration operations are small compared to particulate emissions from a typical solids-producing urea plant. The synthesis and concentration operations are usually uncontrolled except for recycle provisions to recover ammonia. For these reasons, no factor for controlled emissions from synthesis and concentration processes is given in this section.

Uncontrolled emission rates from prill towers may be affected by the following factors: 1) product grade being produced, 2) air flow rate through the tower, 3) type of tower bed, and 4) ambient temperature and humidity.

The total of mass emissions per unit is usually lower for feed grade prill production than for agricultural grade prills, due to lower airflows. Uncontrolled particulate emission rates for fluidized bed prill towers are higher than those for nonfluidized bed prill towers making agricultural grade prills, and are approximately equal to those for nonfluidized bed feed grade prills. Ambient air conditions can affect prill tower emissions. Available data indicate that colder temperatures promote the formation of smaller particles in the prill tower exhaust. Since smaller particles are more difficult to remove, the efficiency of prill tower control devices tends to decrease with ambient temperatures. This can lead to higher emission levels for prill towers operated during cold weather. Ambient humidity can also affect prill tower emissions. Air flow rates must be increased with high humidity, and higher air flow rates usually cause higher emissions.

The design parameters of drum granulators and rotary drum coolers may affect emissions. Drum granulators have an advantage over prill towers in that they are capable of producing very large particles without difficulty. Granulators also require less air for operation than do prill towers. A disadvantage of granulators is their inability to produce the smaller feed grade granules economically. To produce smaller granules, the drum must be operated at a higher seed particle recycle rate. It has been reported that, although the increase in seed material results in a lower bed temperature, the corresponding increase in fines in the granulator causes a higher emission rate. Cooling air passing through the drum granulator entrains approximately 10 to 20 percent of the product. This air stream is controlled with a wet scrubber which is standard process equipment on drum granulators.

In the solids screening process, dust is generated by abrasion of urea particles and the vibration of the screening mechanisms. Therefore, almost all screening operations used in the urea manufacturing industry are enclosed or are covered over the uppermost screen. This operation is a small emission source, therefore particulate emission factors from solids screening are not presented.

Emissions attributable to coating include entrained clay dust from loading, inplant transfer and leaks from the seals of the coater. No emissions data are available to quantify this fugitive dust source.

Bagging operations are sources of particulate emissions. Dust is emitted from each bagging method during the final stages of filling, when dust-laden air is displaced from the bag by urea. Bagging operations are conducted inside warehouses and are usually vented to keep dust out of the workroom area, as mandated by OSHA regulations. Most vents are controlled with baghouses. Nationwide, approximately 90 percent of urea produced is bulk loaded. Few plants control their bulk loading operations. Generation of visible fugitive particles is negligible.

Urea manufacturers presently control particulate matter emissions from prill towers, coolers, granulators and bagging operations. With the exception of bagging operations, urea emission sources are usually controlled with wet scrubbers. Scrubber systems are preferred over dry collection systems primarily for the easy recycling of dissolved urea collected in the device. Scrubber liquors are recycled to the solution concentration process to eliminate waste disposal problems and to recover the urea collected.

Fabric filters (baghouses) are used to control fugitive dust from bagging operations, where humidities are low and binding of the bags is not a problem. However, many bagging operations are uncontrolled.

TABLE 6.14-1 (METRIC UNITS)
EMISSION FACTORS FOR UREA PRODUCTION
All Emission Factors are in
Ratings (A-E) Follow Each Factor

Type of Operation	Particulate[a]				Ammonia			
	Uncontrolled		Controlled		Uncontrolled		Controlled[g]	
	kg/Mg of Product	Factor Rating	kg/Mg of Product	Factor Rating	kg/Mg of Product	Factor Rating	kg/Mg of Product	Factor Rating
Solution formation and concentration[b]	0.0105[c]	A			9.23[d]	A		
Nonfluidized bed prilling								
Agricultural grade[e]	1.9	A	0.032[f]	A	0.43	A		
Feed grade[h]	1.8	A						
Fluidized bed prilling								
Agricultural grade[h]	3.1	A	0.39	A	1.46	A		
Feed grade[h]	1.8	A	0.24	A	2.07	A	1.04	A
Drum granulation[i]	120	A	0.115	A	1.07[j]	A		
Rotary drum cooler	3.89[k]	A	0.10[l]	E	0.0256[k]	A		
Bagging	0.095[l]	E						

[a]Particulate test data were collected using a modification of EPA Reference Method 3. Reference 1, Appendix B explains these modifications.

[b]References 9 and 11. Emissions from the synthesis process are generally combined with emissions from the solution concentration process and vented through a common stack. In the synthesis process, some emission control is inherent in the recycle process where carbamate gases and/or liquids are recovered and recycled.

[c]EPA test data indicated a range of 0.005 to 0.016 kg/Mg (0.010 to 0.032 lb/ton).

[d]EPA test data indicated a range of 4.01 to 14.45 kg/Mg (8.02 to 28.90 lb/ton).

[e]Reference 12. These factors were determined at an ambient temperature of 14 to 21°C (57° to 69°F). The controlled emission factors are based on ducting exhaust through a downcomer and then a wetted fiber filter scrubber achieving a 98.3 percent efficiency. This represents a higher degree of control than is typical in this industry.

[f]Only runs two and three were used (test Series A).

[g]No ammonia control demonstrated by scrubbers installed for particulate control. Some increase in ammonia emissions exiting the control device was noted.

[h]Reference 11. Feed grade factors were determined at an ambient temperature of 29°C (85°F) and agricultural grade factors at an ambient temperature of 27°C (80°F). For fluidized bed prilling, controlled emission factors are based on use of an entrainment scrubber.

[i]References 8 and 9. Controlled emission factors are based on use of a wet entrainment scrubber. Wet scrubbers are standard process equipment on drum granulators. Uncontrolled emissions were measured at the scrubber inlet.

[j]EPA test data indicated a range of 0.955 to 1.20 kg/Mg (1.90 to 2.45 lb/ton).

[k]Reference 10.

[l]Reference 1. Data were provided by industry.

Table 6.14-1. (English Units)
EMISSION FACTORS FOR UREA PRODUCTION

Type of Operation	Particulate[a]				Ammonia			
	Uncontrolled		Controlled		Uncontrolled		Controlled[g]	
	lb/ton of Product	Factor Rating	lb/ton of Product	Factor Rating	lb/ton of Product	Factor Rating	lb/ton of Product	Factor Rating
Solution formation and concentration[b]	0.021[c]	A			18.46[d]	A		
Nonfluidized bed prilling								
Agricultural grade[e]	3.8	A	0.063[f]	A	0.87	A		
Feed grade[h]	3.6	A						
Fluidized bed prilling								
Agricultural grade[h]	6.2	A	0.78	A	2.91	A		
Feed grade[h]	3.6	A	0.48	A	4.14	A	2.08	A
Drum granulation[i]	241	A	0.234	A	2.15[j]	A		
Rotary drum cooler	7.78[k]	A	0.20[l]	E	0.051[k]	A		
Bagging	0.19[l]	E						

[a]Particulate test data were collected using a modification of EPA Reference Method 3. Reference 1, Appendix B explains these modifications.

[b]References 9 and 11. Emissions from the synthesis process are generally combined with emissions from the solution concentration process and vented through a common stack. In the synthesis process, some emission control is inherent in the recycle process where carbamate gases and/or liquids are recovered and recycled.

[c]EPA test data indicated a range of 0.005 to 0.016 kg/Mg (0.010 to 0.032 lb/ton).

[d]EPA test data indicated a range of 4.01 to 14.45 kg/Mg (8.02 to 28.90 lb/ton).

[e]Reference 12. These factors were determined at an ambient temperature of 14 to 21°C (57° to 69°F). The controlled emission factors are based on ducting exhaust through a downcomer and then a wetted fiber filter scrubber achieving a 98.3 percent efficiency. This represents a higher degree of control than is typical in this industry.

[f]Only runs two and three were used (test Series A).

[g]No ammonia control demonstrated by scrubbers installed for particulate control. Some increase in ammonia emissions exiting the control device was noted.

[h]Reference 11. Feed grade factors were determined at an ambient temperature of 29°C (85°F) and agricultural grade factors at an ambient temperature of 27°C (80°F). For fluidized bed prilling, controlled emission factors are based on use of an entrainment scrubber.

[i]References 8 and 9. Controlled emission factors are based on use of a wet entrainment scrubber. Wet scrubbers are standard process equipment on drum granulators. Uncontrolled emissions were measured at the scrubber inlet.

[j]EPA test data indicated a range of 0.955 to 1.20 kg/Mg (1.90 to 2.45 lb/ton).

[k]Reference 10.

[l]Reference 1. Data were provided by industry.

TABLE 6.14-2
UNCONTROLLED PARTICLE SIZE DATA FOR UREA PRODUCTION

Type of Operation	Particle size (cumulative weight %)		
	≤ 10 μm	≤ 5 μm	≤ 2.5 μm
Solid Formation			
Nonfluidized bed prilling	90	84	79
Agricultural grade	85	74	50
Feed grade			
Fluidized bed prilling			
Agricultural grade	60	52	43
Feed grade	24	18	14
Drum granulation	a	a	a
Rotary drum cooler	0.70	0.15	0.04

[a] All particulate matter ≥ 5.7 μm was collected in the cyclone precollector sampling equipment.

References for Section 6.14

1. *Urea Manufacturing Industry: Technical Document*, EPA-450/3-81-001, U.S. Environmental Protection Agency, Research Triangle Park, NC, January 1981.

2. D.F. Bress, M.W. Packbier, "The Startup of Two Major Urea Plants," *Chemical Engineering Progress*, May 1977, p. 80.

3. Written communication from Gary McAlister, U.S. Environmental Protection Agency, Emission Measurement Branch, to Eric Noble, U.S. Environmental Protection Agency, Emission, Industrial Studies Branch, Research Triangle Park, NC, July 28, 1983.

4. *Formaldehyde Use in Urea-Based Fertilizers*, Report of the Fertilizer Institute's Formaldehyde Task Group, The Fertilizer Institute, Washington, DC, February 4, 1983.

5. J.H. Cramer, "Urea Prill Tower Control Meeting 20% Opacity." Presented at the Fertilizer Institute Environment Symposium, New Orleans, LA, April 1980.

6. Written communication from M.I. Bornstein, GCA Corporation, Bedford, MA, to E.A. Noble, U.S. Environmental Protection Agency, Research Triangle Park, NC, August 2, 1978.

7. Written communication from M.I. Bornstein and S.V. Capone, GCA Corporation, Bedford, MA, to E.A. Noble, U.S. Environmental Protection Agency, Research Triangle Park, NC, June 23, 1978.

8. *Urea Manufacture: Agrico Chemical Company Emission Test Report*, EMB Report 78-NHF-4, U.S. Environmental Protection Agency, Research Triangle Park, NC, April 1979.

9. *Urea Manufacture: CF Industries Emission Test Report*, EMB Report 78-NHF-8, U.S. Environmental Protection Agency, Research Triangle Park, NC, May 1979.

10. *Urea Manufacture: Union Oil of California Emission Test Report*, EMB Report 80-NHF-15, U.S. Environmental Protection Agency, Research Triangle Park, NC, September 1980.

11. *Urea Manufacture: W.R. Grace and Company Emission Test Report*, EMB Report 80-NHF-3, U.S. Environmental Protection Agency, Research Triangle Park, NC, December 1979.

12. *Urea Manufacture: Reichhold Chemicals Emission Test Report*, EMB Report 80-NHF-14, U.S. Environmental Protection Agency, Research Triangle Park, NC, August 1980.

13. *North American Fertilizer Capacity Data*, Tennessee Valley Authority, Muscle Shoals, AL, December 1991.

6.18 AMMONIUM SULFATE MANUFACTURE

6.18. General[1-2]

Ammonium sulfate [$(NH_4)_2SO_4$] is commonly used as a fertilizer. In 1991, U. S. facilities produced about 2.7 million megagrams (three million tons) of ammonium sulfate in about 35 plants. Production rates at these plants range from 1.8 to 360 megagrams (2 to 400 tons) per year.

6.18.2 Process Description[1]

About 90 percent of ammonium sulfate is produced by three different processes: 1) as a byproduct of caprolactam [$(CH_2)_5COHN$] production, 2) from synthetic manufacture, and 3) as a coke oven byproduct. The remainder is produced as a byproduct of either nickel or methyl methacrylate manufacture, or from ammonia scrubbing of tail gas at sulfuric acid (H_2SO_4) plants. These minor sources are not discussed here.

Ammonium sulfate is produced as a byproduct from the caprolactam oxidation process stream and the rearrangement reaction stream. Synthetic ammonium sulfate is produced by combining anhydrous ammonia and sulfuric acid in a reactor. Coke oven byproduct ammonium sulfate is produced by reacting the ammonia recovered from coke oven off-gas with sulfuric acid. Figure 6.18-1 is a diagram of typical ammonium sulfate manufacturing for each of the three primary commercial processes.

After formation of the ammonium sulfate solution, manufacturing operations of each process are similar. Ammonium sulfate crystals are formed by circulating the ammonium sulfate liquor through a water evaporator, which thickens the solution. Ammonium sulfate crystals are separated from the liquor in a centrifuge. In the caprolactam byproduct process, the product is first transferred to a settling tank to reduce the liquid load on the centrifuge. The saturated liquor is returned to the dilute ammonium sulfate brine of the evaporator. The crystals, which contain about 1 to 2.5 percent moisture by weight after the centrifuge, are fed to either a fluidized-bed or a rotary drum dryer. Fluidized-bed dryers are continuously steam heated, while the rotary dryers are fired directly with either oil or natural gas or may use steam-heated air.

At coke oven byproduct plants, rotary vacuum filters may be used in place of a centrifuge and dryer. The crystal layer is deposited on the filter and is removed as product. These crystals are generally not screened, although they contain a wide range of particle sizes. They are then carried by conveyors to bulk storage.

At synthetic plants, a small quantity (about 0.05 percent) of a heavy organic (i.e., high molecular weight organic) is added to the product after drying to reduce caking.

Dryer exhaust gases pass through a particulate collection device, such as a wet scrubber. This collection controls emissions and reclaims residual product. After being dried, the ammonium sulfate crystals are screened into coarse and fine crystals. This screening is done in an enclosed area to restrict fugitive dust in the building.

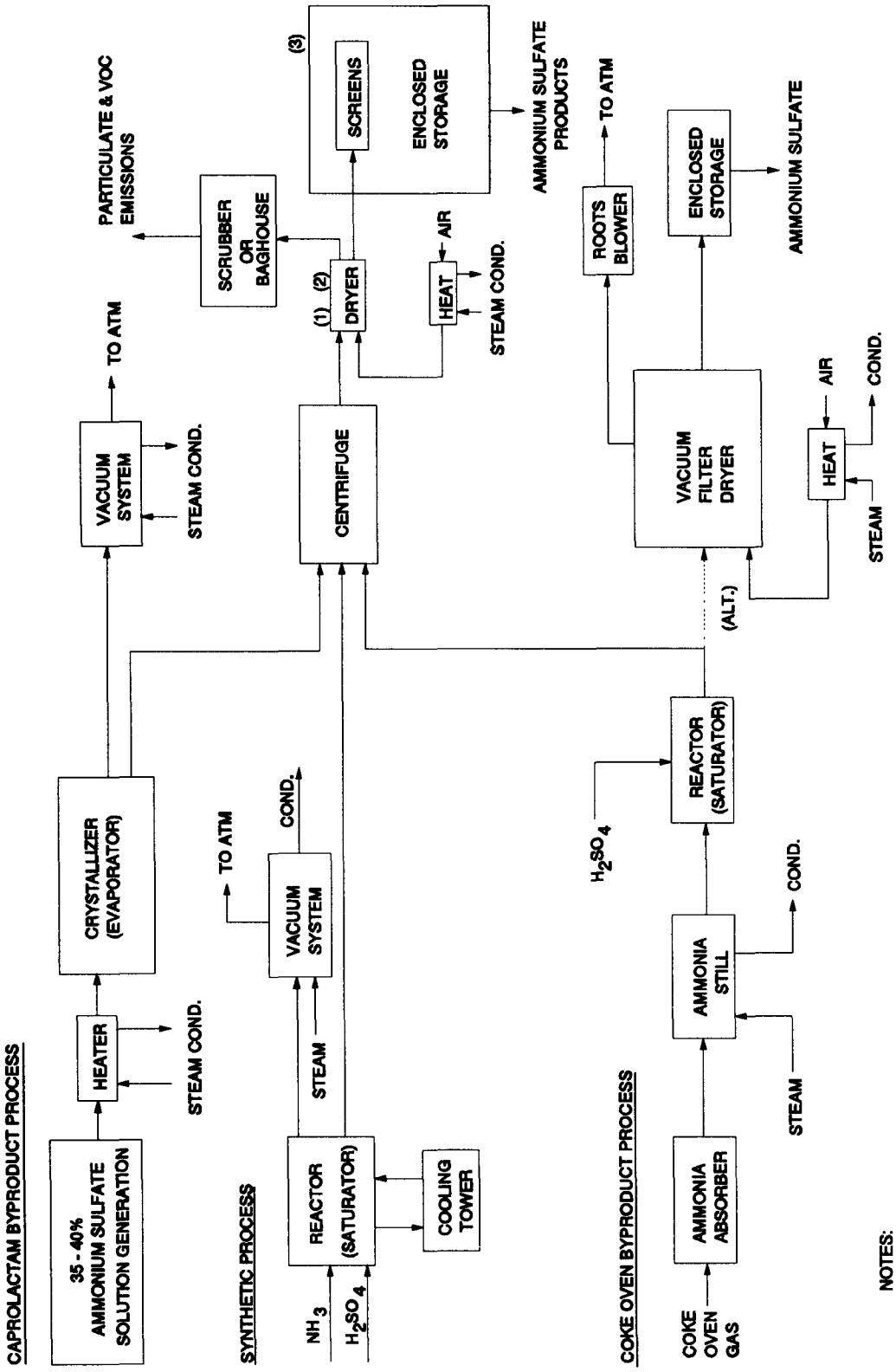


Figure 6.18-1. Typical diagram of ammonium sulfate processes.

6.18.3 Emissions And Controls[1]

Ammonium sulfate particulate is the principal emission from ammonium sulfate manufacturing plants. The gaseous exhaust of the dryers contains nearly all the emitted ammonium sulfate. Other plant processes, such as evaporation, screening and materials handling, are not significant sources of emissions.

The particulate emission rate of a dryer is dependent on gas velocity and particle size distribution. Gas velocity, and thus emission rates, varies according to the dryer type. Generally, the gas velocity of fluidized-bed dryers is higher than for most rotary drum dryers. Therefore, the particulate emission rates are higher for fluidized-bed dryers. At caprolactam byproduct plants, relatively small amounts of volatile organic compounds (VOC) are emitted from the dryers.

Some plants use baghouses for emission control, but wet scrubbers, such as venturi and centrifugal scrubbers, are more suitable for reducing particulate emissions from the dryers. Wet scrubbers use the process streams as the scrubbing liquid so that the collected particulate can be easily recycled to the production system.

Tables 6.18-1 and 6.18-2 shows uncontrolled and controlled particulate and VOC emission factors for various dryer types. The VOC emissions shown apply only to caprolactam byproduct plants.

Table 6.18-1 (Metric Units).
EMISSION FACTORS FOR AMMONIUM SULFATE MANUFACTURE[a]

Dryer Type	Particulate		VOC[b]	
	kg/MG	Emission Factor Rating	kg/Mg	Emission Factor Rating
Rotary dryers				
Uncontrolled	23	C	0.74	C
Wet scrubber	0.02[c]	A	0.11	C
Fluidized-bed dryers				
Uncontrolled	109	C	0.74	C
Wet scrubber	0.14	C	0.11	C

[a] Reference 3. Units are kg of pollutant/Mg of ammonium sulfate produced.
[b] VOC emissions occur only at caprolactam plants. The emissions are caprolactam vapor.
[c] Reference 4.

Table 6.18-2 (English Units).
EMISSION FACTORS FOR AMMONIUM SULFATE MANUFACTURE[a]

Dryer Type	Particulate		VOC[b]	
	lb/ton	Emission Factor Rating	lb/ton	Emission Factor Rating
Rotary dryers				
Uncontrolled	46	C	1.48	B
Wet scrubber	0.04[c]	A	0.22	B
Fluidized-bed dryers				
Uncontrolled	218	C	1.48	B
Wet scrubber	0.28	C	0.22	B

[a] Reference 3. Units are lbs. of pollutant/ton of ammonium sulfate produced
[b] VOC emissions occur only at caprolactam plants. The emissions are caprolactam vapor.
[c] Reference 4.

References for Section 6.18

1. *Ammonium Sulfate Manufacture: Background Information for Proposed Emission Standards*, EPA-450/3-79-034a, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1979.

2. *North American Fertilizer Capacity Data*, Tennessee Valley Authority, Muscle Shoals, AL, December 1991.

3. *Emission Factor Documentation For Section 6.18, Ammonium Sulfate Manufacture*, Pacific Environmental Services, Inc., Research Triangle Park, NC, March 1981.

4. *Compliance Test Report: J.R. Simplot Company*, Pocatello, ID, February, 1990.

7.7 PRIMARY ZINC SMELTING

7.7.1 General[1-2]

Zinc is found in the earth's crust primarily as zinc sulfide (ZnS). Primary uses for zinc include galvanizing of all forms of steel, as a constituent of brass, for electrical conductors, vulcanization of rubber and in primers and paints. Most of these applications are highly dependent upon zinc's resistance to corrosion and its light weight characteristics. In 1991, approximately 260 thousand megagrams of zinc were refined at the four U. S. primary zinc smelters. The annual production volume has remained constant since the 1980s. Three of these four plants, located in Illinois, Oklahoma, and Tennessee) utilize electrolytic technology, and the one plant in Pennsylvania uses electrothermic process. This annual production level approximately equals production capacity, despite a mined zinc ore recovery level of 520 megagrams, a domestic zinc demand of 1190 megagrams, and a secondary smelting production level of only 110 megagrams. As a result, the
U. S. is a leading exporter of zinc concentrates as well as the world's largest importer of refined zinc.

Zinc ores typically may contain from three to eleven percent zinc, along with cadmium, copper, lead, silver, and iron. Beneficiation, or the concentration of the zinc in the recovered ore, is accomplished at or near the mine by crushing, grinding, and flotation process. Once concentrated, the zinc ore is transferred to smelters for the production of zinc or zinc oxide. The primary product of most zinc companies is slab zinc, which is produced in five grades: special high grade, high grade, intermediate, brass special, and prime western. The four U. S. primary smelters also produce sulfuric acid as a byproduct.

7.7.2 Process Description[3]

Reduction of zinc sulfide concentrates to metallic zinc is accomplished through either electrolytic deposition from a sulfate solution or by distillation in retorts or furnaces. Both of these methods begin with the elimination of most of the sulfur in the concentrate through a roasting process, which is described below. A generalized process diagram depicting primary zinc smelting is presented in Figure 7.7-1.

Roasting is a high-temperature process that converts zinc sulfide concentrate to an impure zinc oxide called calcine. Roaster types include multiple-hearth, suspension or fluidized bed. The following reactions occur during roasting:

$$2ZnS + 3O_2 \rightarrow 2ZnO + SO_2 \quad [1]$$

$$2SO_2 + O_2 \rightarrow 2SO_3 \quad [2]$$

In a multiple-hearth roaster, the concentrate drops through a series of nine or more hearths stacked inside a brick lined cylindrical column. As the feed concentrate drops through the furnace, it is first dried by the hot gases passing through the hearths and then oxidized to produce calcine. The reactions are slow and can be sustained only by the addition of fuel.

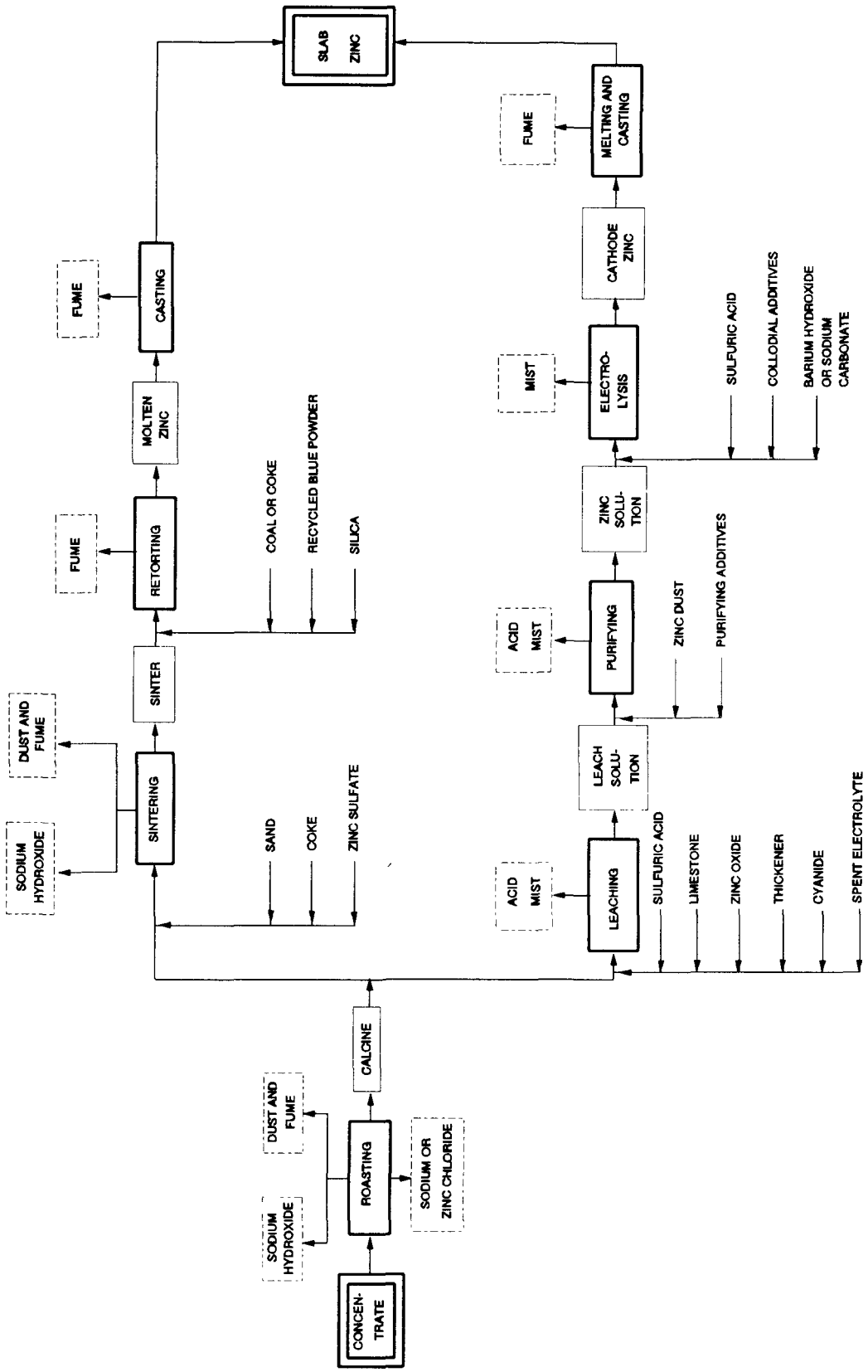


Figure 7.7.2-1. Generalized process flow for primary zinc smelting.

Multiple hearth roasters are unpressurized and operate at about 690°C (1300°F). Operating time depends upon the composition of concentrate and amount of the sulfur removal required. Multiple hearth roasters have the capability of producing a high-purity calcine.

In a suspension roaster, the concentrates are blown into a combustion chamber very similar to that of a pulverized coal furnace. The roaster consists of a refractory-lined cylindrical steel shell, with a large combustion space at the top and two to four hearths in the lower portion, similar to those of a multiple hearth furnace. Additional grinding, beyond that required for a multiple hearth furnace, is normally required to assure that heat transfer to the material is sufficiently rapid for the desulfurization and oxidation reactions to occur in the furnace chamber. Suspension roasters are unpressurized and operate at about 980°C (1800°F).

In a fluidized-bed roaster, finely ground sulfide concentrates are suspended and oxidized in a feedstock bed supported on an air column. As in the suspension roaster, the reaction rates for desulfurization are more rapid than in the older multiple-hearth processes. Fluidized-bed roasters operate under a pressure slightly lower than atmospheric and at temperatures averaging 1000°C (1800°F). In the fluidized-bed process, no additional fuel is required after ignition has been achieved. The major advantages of this roaster are greater throughput capacities and greater sulfur removal capabilities.

Electrolytic processing of desulfurized calcine consists of three basic steps, leaching, purification and electrolysis. Leaching occurs in an aqueous solution of sulfuric acid, yielding a zinc sulfate solution as shown in Equation 3 below.

$$ZnO + SO_3 \rightarrow ZnSO_4 \quad [3]$$

In double leaching, the calcine is first leached in a neutral or slightly alkaline solution, then in an acidic solution, with the liquid passing countercurrent to the flow of calcine. In the neutral leaching solution, sulfates from the calcine dissolve, but only a portion of the zinc oxide enters into solution. The acidic leaching solution dissolves the remainder of the zinc oxide, along with metallic impurities such as arsenic, antimony, cobalt, germanium, nickel, and thallium. Insoluble zinc ferrite, formed during concentrate roasting by the reaction of iron with zinc, remains in the leach residue, along with lead and silver. Lead and silver typically are shipped to a lead smelter for recovery, while the zinc is extracted from the zinc ferrite to increase recovery efficiency.

In the purification process, a number of various reagents are added to the zinc-laden electrolyte in a sequence of steps designed to precipitate the metallic impurities, which otherwise will interfere with deposition of zinc. After purification, concentrations of these impurities are limited to less than 0.05 milligram per liter (4×10^{-7} pounds per gallon). Purification is usually conducted in large agitated tanks. The process takes place at temperatures ranging from 40 to 85°C (104 to 185°F), and pressures ranging from atmospheric to 240 kilopascals (Kpa) (2.4 atmospheres).

In electrolysis, metallic zinc is recovered from the purified solution by passing current through an electrolyte solution, causing zinc to deposit on an aluminum cathode. As the electrolyte is slowly circulated through the cells, water in the electrolyte dissociates, releasing oxygen gas at the anode. Zinc metal is deposited at the cathode and sulfuric acid is regenerated for recycle to the leach process. The sulfuric acid acts as a catalyst in the process as a whole.

Electrolytic zinc smelters contain as many as several hundred cells. A portion of the electrical energy is converted into heat, which increases the temperature of the electrolyte.

Electrolytic cells operate at temperature ranges from 30 to 35°C (86 to 95°F) and at atmospheric pressure. A portion of the electrolyte is continuously circulated through the cooling towers both to cool and concentrate the electrolyte through evaporation of water. The cooled and concentrated electrolyte is then recycled to the cells. Every 24 to 48 hours, each cell is shut down, the zinc-coated cathodes are removed and rinsed, and the zinc is mechanically stripped from the aluminum plates.

The electrothermic distillation retort process, as it exists at one U. S. plant, was developed by the St. Joe Minerals Corporation in 1930. The principal advantage of this pyrometallurgical technique over electrolytic processes is its ability to accommodate a wide variety of zinc-bearing materials, including secondary items such as calcine derived from electric arc furnace (EAF) dust. Electrothermic processing of desulfurized calcine begins with a down draft sintering operation, in which grate pallets are joined to form a continuous conveyor system. The sinter feed is essentially a mixture of roaster calcine and EAF calcine. Combustion air is drawn down through the conveyor, and impurities such as lead, cadmium, and halides in the sinter feed are driven off and collected in a bag filter. The product sinter typically includes 48 percent zinc, 8 percent iron, 5 percent aluminum, 4 percent silicon, 2.5 percent calcium, and smaller quantities of magnesium, lead, and other metals.

Electric retorting with its greater thermal efficiency than externally heated furnaces, is the only pyrometallurgical technique utilized by the U. S. primary zinc industry, now and in the future. Product sinter and, possibly, secondary zinc materials are charged with coke to an electric retort furnace. The charge moves downward from a rotary feeder in the furnace top into a refractory-lined vertical cylinder. Paired graphite electrodes protrude from the top and bottom of this cylinder, producing a current flow. The coke serves to provide electrical resistance, producing heat and generating the carbon monoxide required for the reduction process. Temperatures of 1400°C (2600°F) are attained, immediately vaporizing zinc oxides according to the following reaction:

$$ZnO + CO \rightarrow Zn\ (vapor) + CO_2 \qquad [4]$$

The zinc vapor and carbon dioxide pass to a vacuum condenser, where zinc is recovered by bubbling through a molten zinc bath. Over 95 percent of the zinc vapor leaving the retort is condensed to liquid zinc. The carbon dioxide is regenerated with carbon, and the carbon monoxide is recycled back to the retort furnace.

7.7.3 Emissions And Controls

Each of the two smelting processes generates emissions along the various process steps. The roasting process in a zinc smelter is typically responsible for more than 90 percent of the potential SO_2 emissions. About 93 to 97 percent of the sulfur in the feed is emitted as sulfur oxides. Concentrations of SO_2 in the offgas vary with the type of roaster operation. Typical SO_2 concentrations for multiple hearth, suspension, and fluidized bed roasters are 4.5 to 6.5 percent, 10 to 13 percent, and 7 to 12 percent, respectively. Sulfur dioxide emissions from the roasting processes at all four U. S. primary zinc processing facilities are recovered at on-site sulfuric acid plants. Much of the particulate matter emitted from primary zinc processing facilities is also attributable to the concentrate roasters. The amount and composition of particulate varies with operating parameters, such as air flow rate and equipment configuration. Various combinations of control devices such as cyclones, electrostatic precipitators (ESP), and baghouses can be used on roasters and on sintering machines, achieving 94 to 99 percent emission reduction.

Controlled and uncontrolled particulate emission factors for points within a zinc smelting facility are presented in Tables 7.7-1 and 7.7-2. Fugitive emission factors are presented in Tables 7.7-3 and 7.7-4. These emission factors should be applied carefully. Emission factors for sintering operations are derived from data from a single facility no longer operating. Others are estimated based on similar operations in the steel, lead and copper industries. Testing on one electrothermic primary zinc smelting facility indicates that cadmium, chromium, lead, mercury, nickel, and zinc are contained in the offgases from both the sintering machine and the retort furnaces.

Table 7.7-1 (Metric Units).
PARTICULATE EMISSION FACTORS FOR ZINC SMELTING[a]

Process	Uncontrolled	Emission Factor Rating	Controlled	Emission Factor Rating
Roasting				
Multiple hearth[b] (SCC 3-03-030-02)	113	E		
Suspension[c] (SCC 3-03-030-07)	2000	E	4	E
Fluidized bed[d] (SCC 3-03-030-08)	2167	E		
Sinter plant (SCC 3-03-030-03)				
Uncontrolled[e]	62.5	E		
With cyclone[f]			24.1	E
With cyclone and ESP[g]			8.25	E
Electric retort[h] (SCC 3-03-030-21)	10.0	E		
Electrolytic process[j] (SCC 3-03-030-06)	3.3	E		

[a]Factors are for kg/Mg of zinc produced. SCC = Source Classification Code. ESP = Electrostatic precipitator.
[b]References 2,4. Averaged from an estimated 10% of feed released as particulate, zinc production rate at 60% of roaster feed rate, and other estimates.
[c]References 2,4. Based on an average 60% of feed released as particulate emission and a zinc production rate at 60% of roaster feed rate. Controlled emissions based on 20% dropout in waste heat boiler and 99.5% dropout in cyclone and ESP.
[d]References 4,7. Based on an average 65% of feed released as particulate emissions and a zinc production rate of 60 percent of roaster feed rate.
[e]Reference 4. Based on unspecified industrial source data.
[f]Reference 8. Data not necessarily compatible with uncontrolled emissions.
[g]Reference 8.
[h]Reference 1. Based on unspecified industrial source data.
[j]Reference 2.

Table 7.7-2 (English Units).
PARTICULATE EMISSION FACTORS FOR ZINC SMELTING[a]

Process	Uncontrolled	Emission Factor Rating	Controlled	Emission Factor Rating
Roasting				
Multiple hearth[b] (SCC 3-03-030-02)	227	E		
Suspension[c] (SCC 3-03-030-07)	2000	E	8	E
Fluidized bed[d] (SCC 3-03-030-08)	2167	E		
Sinter plant (SCC 3-03-030-03)				
Uncontrolled[e]	125	E		
With cyclone[f]			48.2	E
With cyclone and ESP[g]			16.5	E
Electric retort[h] (SCC 3-03-030-21)	20.0	E		
Electrolytic process[j] (SCC 3-03-030-06)	6.6	E		

[a]Factors are for lb/ton of zinc produced. SCC = Source Classification Code. ESP = Electrostatic precipitator.
[b]References 2,4. Averaged from an estimated 10% of feed released as particulate, zinc production rate at 60% of roaster feed rate, and other estimates.
[c]References 2,4. Based on an average 60% of feed released as particulate emission and a zinc production rate at 60% of roaster feed rate. Controlled emissions based on 20% dropout in waste heat boiler and 99.5% dropout in cyclone and ESP.
[d]References 4,7. Based on an average 65% of feed released as particulate emissions and a zinc production rate of 60 percent of roaster feed rate.
[e]Reference 4. Based on unspecified industrial source data.
[f]Reference 8. Data not necessarily compatible with uncontrolled emissions.
[g]Reference 8.
[h]Reference 1. Based on unspecified industrial source data.
[j]Reference 2.

Table 7.7-3 (Metric Units).
UNCONTROLLED FUGITIVE PARTICULATE EMISSION FACTORS
FOR SLAB ZINC SMELTING[a]

Process	Emissions	Emission Factor Rating
Roasting	Negligible	
Sinter plant[b]		
Wind box (SCC 3-03-030-19)	0.12 - 0.55	E
Discharge screens (SCC 3-03-030-20)	0.28 - 1.22	E
Retort building[c] (SCC 3-03-030-24)	1.0 - 2.0	E
Casting[d] (SCC 3-03-030-11)	1.26	E

[a]Reference 9. Factors are in kg/Mg of product. SCC = Source Classification Code.
[b]From steel industry operations for which there are emission factors. Based on quantity of sinter produced.
[c]From lead industry operations.
[d]From copper industry operations.

Table 7.7-4 (English Units).
UNCONTROLLED FUGITIVE PARTICULATE EMISSION FACTORS
FOR SLAB ZINC SMELTING

Process	Emissions	Emission Factor Rating
Roasting	Negligible	
Sinter plant[b]		
Wind box (SCC 3-03-030-19)	0.24 - 1.10	E
Discharge screens (SCC 3-03-030-20)	0.56 - 2.44	E
Retort building[c] (SCC 3-03-030-24)	2.0 - 4.0	E
Casting[d] (SCC 3-03-030-11)	2.52	E

[a]Reference 9. Factors are in lb/ton of product. SCC = Source Classification Code.
[b]From steel industry operations for which there are emission factors. Based on quantity of sinter produced.
[c]From lead industry operations.
[d]From copper industry operations.

References for Section 7.7

1. J. H. Jolly, "Zinc", *Mineral Commodity Summaries 1992*, U. S. Department Of The Interior, Washington, DC, 1992.

2. J. H. Jolly, "Zinc", *Minerals Yearbook 1989*, U. S. Department Of The Interior, Washington, DC, 1990.

3. R. L. Williams, "The Monaca Electrothermic Smelter - The Old Becomes The New", *Lead-Zinc '90*, The Minerals, Metals & Materials Society, Philadelphia, PA, 1990.

4. *Environmental Assessment Of The Domestic Primary Copper, Lead And Zinc Industries*, EPA-600/2-82-066, U. S. Environmental Protection Agency, Cincinnati, OH, October 1978.

5. *Particulate Pollutant System Study, Volume I: Mass Emissions*, APTD-0743, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1971.

6. G. Sallee, Personal Communication, Midwest Research Institute, Kansas City, MO, June 1970.

7. *Systems Study For Control Of Emissions In The Primary Nonferrous Smelting Industry, Volume I*, APTD-1280, U. S. Environmental Protection Agency, Research Triangle Park, NC, June 1969.

8. R. B. Jacko and D. W. Nevendorf, "Trace Metal Emission Test Results From A Number Of Industrial And Municipal Point Sources", *Journal Of The Air Pollution Control Association, 27*(10):989-994, October 1977.

9. *Technical Guidance For Control Of Industrial Process Fugitive Particulate Emissions*, EPA-450/3-77-010, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1977.

10. *Background Information For New Source Performance Standards: Primary Copper, Zinc And Lead Smelters, Volume I: Proposed Standards*, EPA-450/2-74-002a, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1974.

11. Written communication from J. D. Reese, Zinc Corporation Of America, Monaca, PA, to C. M. Campbell, Pacific Environmental Services, Inc., Research Triangle Park, NC, 18 November 1992.

12. *Emission Study Performed For Zinc Corporation Of America At The Monaca Facilities*, 14-30 May 1991, EMC Analytical, Inc., Gilberts, IL, 27 April 1992.

7.14 SECONDARY ZINC PROCESSING

7.14.1 General[1-2]

The secondary zinc industry processes scrap metals for the recovery of zinc in the form of in the form of zinc slabs, zinc oxide, or zinc dust. There are currently 10 secondary zinc recovery plants operating in the U. S., with an aggregate capacity of approximately 60 megagrams (60 tons) per year.

7.14.2 Process Description

Zinc recovery involves three general operations performed on scrap, pretreatment, melting, and refining. Processes typically used in each operation are shown in Figure 7.14-1.

7.14.2.1 Scrap Pretreatment

Scrap metal is delivered to the secondary zinc processor as ingots, rejected castings, flashing and other mixed metal scrap containing zinc. Scrap pretreatment includes: (1) sorting, (2) cleaning, (3) crushing and screening, (4) sweating, and (5) leaching.

In the sorting operation, zinc scrap is manually separated according to zinc content and any subsequent processing requirements. Cleaning removes foreign materials to improve product quality and recovery efficiency. Crushing facilitates the ability to separate the zinc from the contaminants. Screening and pneumatic classification concentrates the zinc metal for further processing.

A sweating furnace (rotary, reverberatory, or muffle furnace) slowly heats the scrap containing zinc and other metals to approximately 364°C (787°F). This temperature is sufficient to melt zinc but is still below the melting point of the remaining metals. Molten zinc collects at the bottom of the sweat furnace and is subsequently recovered. The remaining scrap metal is cooled and removed to be sold to other secondary processors.

Leaching with sodium carbonate solution converts dross and skimmings to zinc oxide, which can be reduced to zinc metal. The zinc containing material is crushed and washed with water, separating contaminants from zinc-containing metal. The contaminated aqueous stream is treated with sodium carbonate to convert zinc chloride into sodium chloride (NaCl) and insoluble zinc hydroxide (ZnOH). The NaCl is separated from the insoluble residues by filtration and settling. The precipitate zinc hydroxide is dried and calcined (dehydrated into a powder at high temperature) to convert it into crude zinc oxide (ZnO). The ZnO product is usually refined to zinc at primary zinc smelters. The washed zinc-containing metal portion becomes the raw material for the melting process.

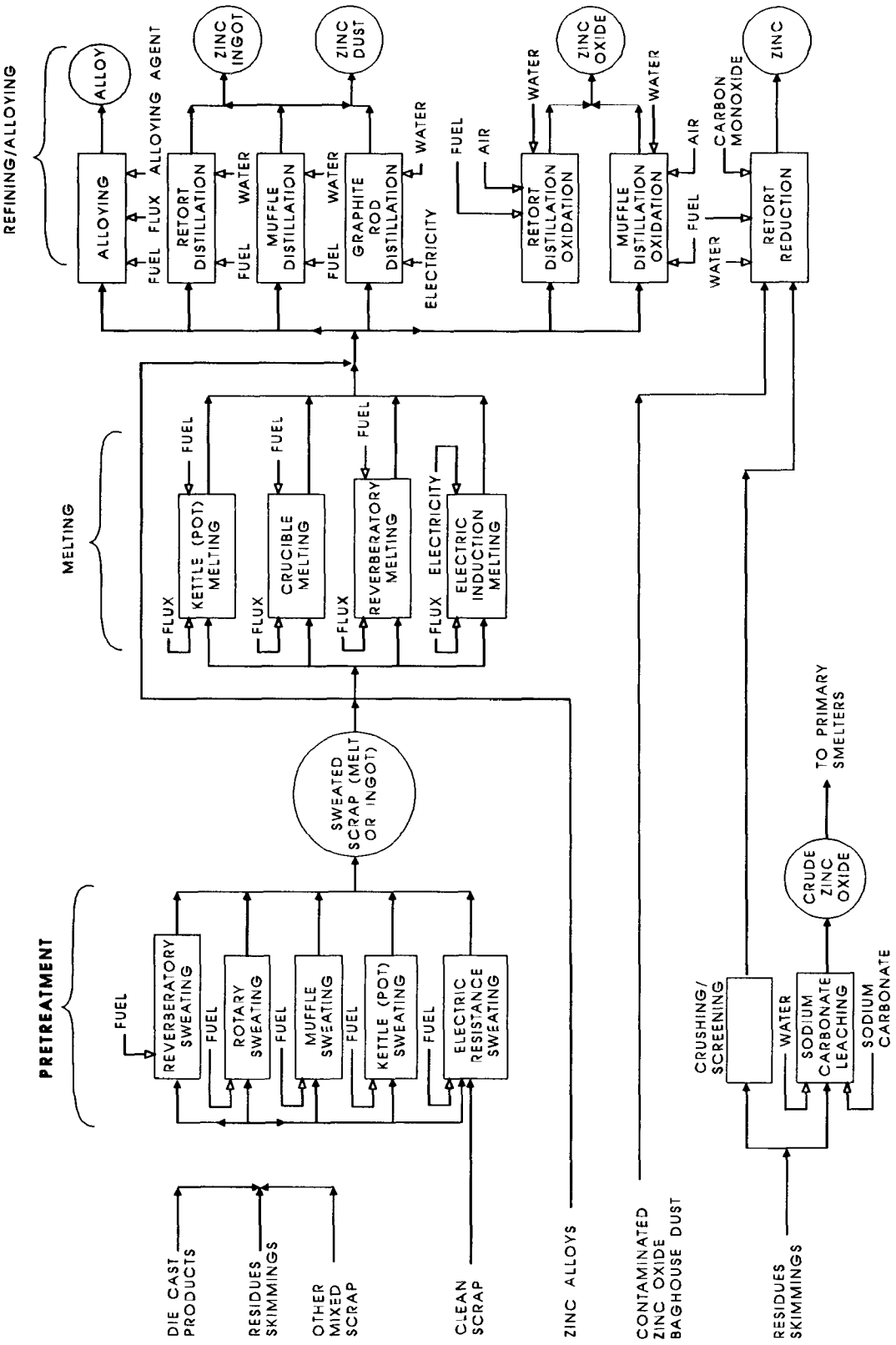


Figure 7.14-1. Secondary zinc recovery process.

7.14.2.2 Melting

Zinc scrap is melted in kettle, crucible, reverberatory, and electric induction furnaces. Flux is used in these furnaces to trap impurities from the molten zinc. Facilitated by agitation, flux and impurities float to the surface of the melt as dross, and is skimmed from the surface. The remaining molten zinc may be poured into molds or transferred to the refining operation in a molten state.

Zinc alloys are produced from pretreated scrap during sweating and melting processes. The alloys may contain small amounts of copper, aluminum, magnesium, iron, lead, cadmium and tin. Alloys containing 0.65 to 1.25 percent copper are significantly stronger than unalloyed zinc.

7.14.2.3 Refining

Refining processes remove further impurities in clean zinc alloy scrap and in zinc vaporized during the melt phase in retort furnaces, as shown in Figure 7.14-2.

Molten zinc is heated until it vaporizes. Zinc vapor is condensed and recovered in several forms, depending upon temperature, recovery time, absence or presence of oxygen, and equipment used during zinc vapor condensation. Final products from refining processes include zinc ingots, zinc dust, zinc oxide, and zinc alloys.

Distillation retorts and furnaces are used either to reclaim zinc from alloys or to refine crude zinc. Bottle retort furnaces consist of a pear-shaped ceramic retort (a long-necked vessel used for distillation). Bottle retorts are filled with zinc alloys and heated until most of the zinc is vaporized, sometimes as long as 24 hours. Distillation involves vaporization of zinc at temperatures from 982 to 1249°C (1800 to 2280°F) and condensation as zinc dust or liquid zinc. Zinc dust is produced by vaporization and rapid cooling, and liquid zinc results when the vaporous product is condensed slowly at moderate temperatures. The melt is cast into ingots or slabs.

A muffle furnace is a continuously charged retort furnace, which can operate for several days at a time.
Molten zinc is charged through a feed well that also acts as an airlock. Muffle furnaces generally have a much greater vaporization capacity than bottle retort furnaces. They produce both zinc ingots and zinc oxide of 99.8 percent purity.

Pot melting, unlike bottle retort and muffle furnaces, does not incorporate distillation as a part of the refinement process. This method merely monitors the composition of the intake to control the composition of the product. Specified die-cast scraps containing zinc are melted in a steel pot. Pot melting is a simple indirect heat melting operation where the final alloy cast into zinc alloy slabs is controlled by the scrap input into the pot.

Furnace distillation with oxidation produces zinc oxide dust. These processes are similar to distillation without the condenser. Instead of entering a condenser, the zinc vapor discharges directly into an air stream leading to a refractory-lined combustion chamber. Excess air completes the oxidation and cools the zinc oxide dust before it is collected in a fabric filter.

Zinc oxide is transformed into zinc metal though a retort reduction process using coke as a reducing agent. Carbon monoxide produced by the partial oxidation of the coke reduces the zinc oxide to metal and carbon dioxide. The zinc vapor is recovered by condensation.

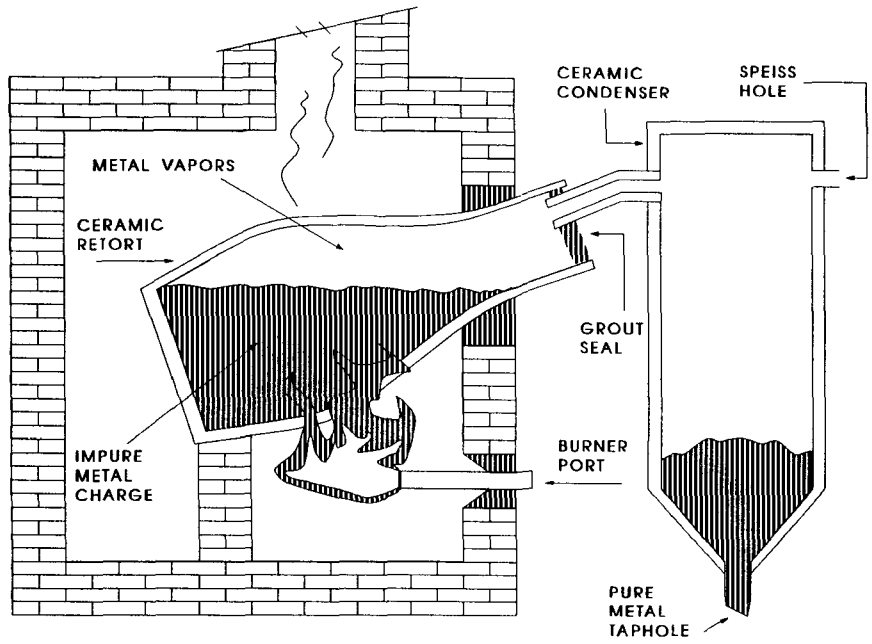


Figure 7.14-2. Zinc retort distillation furnace.

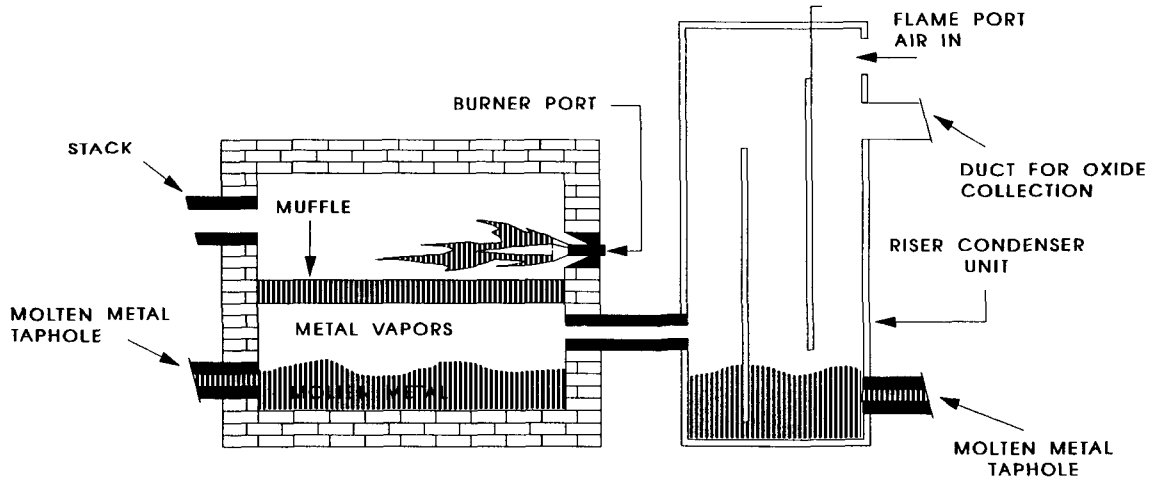


Figure 7.14-3. Muffle furnace and condenser.

7.14.3 Emissions[1-4]

Process and fugitive emission factors for secondary zinc operations are tabulated in Tables 7.14-1 through 7.14-4. Emissions from sweating and melting operations consist of particulate, zinc fumes, other volatile metals, flux fumes, and smoke generated by the incomplete combustion of grease, rubber and plastics in zinc scrap. Zinc fumes are negligible at low furnace temperatures. Flux emissions may be minimized by using a nonfuming flux. In production requiring special fluxes that do generate fumes, fabric filters may be used to collect emissions. Substantial emissions may arise from incomplete combustion of carbonaceous material in the zinc scrap. These contaminants are usually controlled by afterburners.

Particulate emissions from sweating and melting are most commonly recovered by fabric filter. In one application on a muffle sweating furnace, a cyclone and fabric filter achieved particulate recovery efficiencies in excess of 99.7 percent. In one application on a reverberatory sweating furnace, a fabric filter removed 96.3 percent of the particulate. Fabric filters show similar efficiencies in removing particulate from exhaust gases of melting furnaces.

Crushing and screening operations are also sources of dust emissions. These emissions are composed of zinc, aluminum, copper, iron, lead, cadmium, tin, and chromium. They can be recovered by hooded exhausts used as capture devices and can be controlled with fabric filters.

The sodium carbonate leaching process emits zinc oxide dust during the calcining operation (oxidizing precipitate into powder at high temperature). This dust can be recovered in fabric filters, although zinc chloride in the dust may cause plugging problems.

Emissions from refining operations are mainly metallic fumes. Distillation/oxidation operations emit their entire zinc oxide product in the exhaust gas. Zinc oxide is usually recovered in fabric filters with collection efficiencies of 98 to 99 percent.

Table 7.14-1 (Metric Units).
UNCONTROLLED PARTICULATE EMISSION FACTORS FOR SECONDARY ZINC SMELTING[a]

Operation	Emissions	Emission Factor Rating
Reverberatory sweating[b] (in mg/Mg feed material)		
Clean metallic scrap (SCC 3-04-008-18)	Negligible	
General metallic scrap (SCC 3-04-008-28)	6.5	C
Residual scrap (SCC 3-04-008-38)	16	C
Rotary sweating[c] (SCC 3-04-008-09)	5.5 - 12.5	C
Muffle sweating[c] (SCC 3-04-008-10)	5.4 - 16	C
Kettle sweating[b]		
Clean metallic scrap (SCC 3-04-008-14)	Negligible	
General metallic scrap (SCC 3-04-008-24)	5.5	C
Residual scrap (SCC 3-04-008-34)	12.5	C
Electric resistance sweating[c] (SCC 3-04-008-11)	< 5	C
Sodium carbonate leaching calcining[d] (SCC 3-04-008-06)	44.5	C
Kettle pot[d], mg/Mg product (SCC 3-04-008-03)	0.05	C
Crucible melting (SCC 3-04-008-42)	ND	
Reverberatory melting (SCC 3-04-008-42)	ND	
Electric induction melting (SCC 3-04-008-43)	ND	
Alloying (SCC 3-04-008-40)	ND	
Retort and muffle distillation, in kg/Mg of product		
Pouring[c] (SCC 3-04-008-51)	0.2 - 0.4	C
Casting[c] (SCC 3-04-008-52)	0.1 - 0.2	C
Muffle distillation[d] (SCC 3-04-008-02	22.5	C
Graphite rod distillation[c,e] (SCC 3-04-008-53)	Negligible	C
Retort distillation/oxidation[f] (SCC 3-04-008-54)	10 - 20	C
Muffle distillation/oxidation[f] (SCC 3-04-008-55)	10 - 20	C
Retort reduction (SCC 3-04-008-01)	23.5	C
Galvanizing[d] (SCC 3-04-008-05)	2.5	C

[a] Factors are for kg/Mg of zinc used, except as noted. SCC = Source Classification Code. ND = no data.
[b] Reference 3.
[c] Reference 4.
[d] References 5-7.
[e] Reference 1.
[f] Reference 4. Factors are for kg/Mg of ZnO produced. All product zinc oxide dust is carried over in the exhaust gas from the furnace and is recovered with 98 - 99 percent efficiency.

Table 7.14-2 (English Units).
UNCONTROLLED PARTICULATE EMISSION FACTORS FOR SECONDARY ZINC SMELTING[a]

Operation	Emissions	Emission Factor Rating
Reverberatory sweating[b] (in mg/Mg feed material)		
Clean metallic scrap (SCC 3-04-008-18)	Negligible	
General metallic scrap (SCC 3-04-008-28)	13	C
Residual scrap (SCC 3-04-008-38)	32	C
Rotary sweating[c] (SCC 3-04-008-09)	11 - 25	C
Muffle sweating[c] (SCC 3-04-008-10)	10.8 - 32	C
Kettle sweating[b]		
Clean metallic scrap (SCC 3-04-008-14)	Negligible	
General metallic scrap (SCC 3-04-008-24)	11	C
Residual scrap (SCC 3-04-008-34)	25	C
Electric resistance sweating[c] (SCC 3-04-008-11)	< 10	C
Sodium carbonate leaching calcining[d] (SCC 3-04-008-06)	89	C
Kettle pot[d], mg/Mg product (SCC 3-04-008-03)	0.1	C
Crucible melting (SCC 3-04-008-42)	ND	
Reverberatory melting (SCC 3-04-008-42)	ND	
Electric induction melting (SCC 3-04-008-43)	ND	
Alloying (SCC 3-04-008-40)	ND	
Retort and muffle distillation, in lb/ton of product		
Pouring[c] (SCC 3-04-008-51)	0.4 - 0.8	C
Casting[c] (SCC 3-04-008-52)	0.2 - 0.4	C
Muffle distillation[d] (SCC 3-04-008-02	45	C
Graphite rod distillation[c,e] (SCC 3-04-008-53)	Negligible	C
Retort distillation/oxidation[f] (SCC 3-04-008-54)	20 - 40	C
Muffle distillation/oxidation[f] (SCC 3-04-008-55)	20 - 40	C
Retort reduction (SCC 3-04-008-01)	47	C
Galvanizing[d] (SCC 3-04-008-05)	5	C

[a] Factors are for lb/ton of zinc used, except as noted. SCC = Source Classification Code. ND = no data.
[b] Reference 3.
[c] Reference 4.
[d] References 5-7.
[e] Reference 1.
[f] Reference 4. Factors are for lb/ton of ZnO produced. All product zinc oxide dust is carried over in the exhaust gas from the furnace and is recovered with 98 - 99 percent efficiency.

Table 7.14-3 (Metric Units).
FUGITIVE PARTICULATE EMISSION FACTORS FOR
SECONDARY ZINC SMELTING[a]

Operation	Emissions	Emission Factor Rating
Reverberatory sweating[b] (SCC 3-04-008-61)	0.63	E
Rotary sweating[b] (SCC 3-04-008-62)	0.45	E
Muffle sweating[b] (SCC 3-04-008-63)	0.54	E
Kettle (pot) sweating[b] (SCC 3-04-008-64)	0.28	E
Electrical resistance sweating, per kg processed[b] (SCC 3-04-008-65)	0.25	E
Crushing/screening[c] (SCC 3-04-008-12)	2.13	E
Sodium carbonate leaching (SCC 3-04-008-66)	ND	
Kettle (pot) melting furnace[b] (SCC 3-04-008-67)	0.0025	E
Crucible melting furnace[d] (SCC 3-04-008-68)	0.0025	E
Reverberatory melting furnace[b] (SCC 3-04-008-69)	0.0025	E
Electric induction melting[b] (SCC 3-04-008-70)	0.0025	E
Alloying retort distillation (SCC 3-04-008-71)	ND	
Retort and muffle distillation (SCC 3-04-008-72)	1.18	E
Casting[b] (SCC 3-04-008-73)	0.0075	E
Graphite rod distillation (SCC 3-04-008-74)	ND	
Retort distillation/oxidation (SCC 3-04-008-75)	ND	
Muffle distillation/oxidation (SCC 3-04-008-76)	ND	
Retort reduction (SCC 3-04-008-77)	ND	

[a]Reference 8. Factors are kg/Mg of end product, except as noted. SCC = Source Classification Code. ND = no data.
[b]Estimate based on stack emission factor given in Reference 1, assuming fugitive emissions to be equal to five % of stack emissions.
[c]Reference 1. Factors are for kg/Mg of scrap processed. Average of reported emission factors.
[d]Engineering judgment, assuming fugitive emissions from crucible melting furnace to be equal to fugitive emissions from kettle (pot) melting furnace.

Table 7.14-4 (English Units).
FUGITIVE PARTICULATE EMISSION FACTORS FOR SECONDARY ZINC SMELTING[a]

Operation	Emissions	Emission Factor Rating
Reverberatory sweating[b] (SCC 3-04-008-61)	1.30	E
Rotary sweating[b] (SCC 3-04-008-62)	0.90	E
Muffle sweating[b] (SCC 3-04-008-63)	1.07	E
Kettle (pot) sweating[b] (SCC 3-04-008-64)	0.56	E
Electrical resistance sweating, per ton processed[b] (SCC 3-04-008-65)	0.50	E
Crushing/screening[c] (SCC 3-04-008-12)	4.25	E
Sodium carbonate leaching (SCC 3-04-008-66)	ND	
Kettle (pot) melting furnace[b] (SCC 3-04-008-67)	0.005	E
Crucible melting furnace[d] (SCC 3-04-008-68)	0.005	E
Reverberatory melting furnace[b] (SCC 3-04-008-69)	0.005	E
Electric induction melting[b] (SCC 3-04-008-70)	0.005	E
Alloying retort distillation (SCC 3-04-008-71)		
Retort and muffle distillation (SCC 3-04-008-72)	2.36	E
Casting[b] (SCC 3-04-008-73)	0.015	E
Graphite rod distillation (SCC 3-04-008-74)	ND	
Retort distillation/oxidation (SCC 3-04-008-75)	ND	
Muffle distillation/oxidation (SCC 3-04-008-76)	ND	
Retort reduction (SCC 3-04-008-77)	ND	

[a]Reference 8. Factors are lb/ton of end product, except as noted. SCC = Source Classification Code. ND = no data.
[b]Estimate based on stack emission factor given in Reference 1, assuming fugitive emissions to be equal to five % of stack emissions.
[c]Reference 1. Factors are for lb/ton of scrap processed. Average of reported emission factors.
[d]Engineering judgment, assuming fugitive emissions from crucible melting furnace to be equal to fugitive emissions from kettle (pot) melting furnace.

References for Section 7.14

1. William M. Coltharp, *et al., Multimedia Environmental Assessment Of The Secondary Nonferrous Metal Industry*, Draft, EPA Contract No. 68-02-1319, Radian Corporation, Austin, TX, June 1976.

2. John A. Danielson, *Air Pollution Engineering Manual*, 2nd Edition, AP-40, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1973. Out of Print.

3. W. Herring, *Secondary Zinc Industry Emission Control Problem Definition Study (Part I)*, APTD-0706, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1971.

4. H. Nack, *et al., Development Of An Approach To Identification Of Emerging Technology And Demonstration Opportunities*, EPA-650/2-74-048, U. S. Environmental Protection Agency, Cincinnati, Ohio, May 1974.

5. G. L. Allen, *et al., Control Of Metallurgical And Mineral Dusts And Fumes In Los Angeles County,* Report Number 7627, U. S. Department Of The Interior, Washington, DC, April 1952.

6. *Restricting Dust And Sulfur Dioxide Emissions From Lead Smelters*, VDI Number 2285, U. S. Department Of Health And Human Services, Washington, DC, September 1961.

7. W. F. Hammond, *Data On Nonferrous Metallurgical Operations*, Los Angeles County Air Pollution Control District, Los Angeles, CA, November 1966.

8. *Assessment Of Fugitive Particulate Emission Factors For Industrial Processes,* EPA-450/3-78-107, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1978.

9. *Source Category Survey: Secondary Zinc Smelting And Refining Industry,* EPA-450/3-80-012, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1980.

7.16 LEAD OXIDE AND PIGMENT PRODUCTION

7.16.1 General[1-2,7]

Lead oxide is a general term and can be either lead monoxide, or "litharge" (PbO); lead tetroxide, or "red lead" (Pb_3O_4); or black, or "gray", oxide which is a mixture of 70 percent lead monoxide and 30 percent metallic lead. Black lead is made for specific use in the manufacture of lead acid storage batteries. Because of the size of the lead acid battery industry, lead monoxide is the most important commercial compound of lead, based on volume. Total oxide production in 1989 was 57,984 megagrams (64,000 tons).

Litharge is used primarily in the manufacture of various ceramic products. Because of its electrical and electronic properties, litharge is also used in capacitors, Vidicon® tubes, and electrophotographic plates, as well as in ferromagnetic and ferroelectric materials. It is also used as an activator in rubber, a curing agent in elastomers, a sulfur removal agent in the production of thioles and in oil refining, and an oxidation catalyst in several organic chemical processes. It also has important markets in the production of many lead chemicals, dry colors, soaps (i. e., lead stearate), and driers for paint. Another important use of litharge is the production of lead salts, particularly those used as stabilizers for plastics, notably polyvinyl chloride materials.

The major lead pigment is red lead (Pb_3O_4), which is used principally in ferrous metal protective paints. Other lead pigments include white lead and lead chromates. There are several commercial varieties of white lead including leaded zinc oxide, basic carbonate white lead, basic sulfate white lead, and basic lead silicates. Of these, the most important is leaded zinc oxide, which is used almost entirely as white pigment for exterior oil-based paints.

7.16.2 Process Description[8]

Black oxide is usually produced by a Barton Pot process. Basic carbonate white lead production is based on the reaction of litharge with acetic acid or acetate ions. This product is then reacted with carbon dioxide will form lead carbonate. White leads (other than carbonates) are made either by chemical, fuming, or mechanical blending processes. Red lead is produced by oxidizing litharge in a reverberatory furnace. Chromate pigments are generally manufactured by precipitation or calcination as in the following equation:

$$Pb(NO_3)_2 + Na_2(CrO_4) \rightarrow PbCrO_4 + 2\ NaNO_3 \qquad [1]$$

Commercial lead oxides can all be prepared by wet chemical methods. With the exception of lead dioxide, lead oxides are produced by thermal processes in which lead is directly oxidized with air. The processes may be classified according to the temperature of the reaction: 1) low temperature, below the melting point of lead; 2) moderate temperature, between the melting points of lead and of lead monoxide; and 3) high temperature, above the melting point of lead monoxide.

Low Temperature Oxidation - Low temperature oxidation of lead is accomplished by tumbling slugs of metallic lead in a ball mill equipped with an air flow. The air flow provides oxygen and is used as a coolant. If some form of cooling were not supplied, the heat generated by the oxidation of the lead plus the mechanical heat of the tumbling charge would raise the charge temperature above the melting point of lead. The ball mill product is a "leady" oxide with 20 to 50 percent free lead.

Moderate Temperature Oxidation - Three processes are used commercially in the moderate temperature range: 1) refractory furnace, 2) rotary tube furnace, and 3) the Barton Pot process. In the refractory furnace process, a cast steel pan is equipped with a rotating vertical shaft and a horizontal crossarm mounted with plows. The plows move the charge continuously to expose fresh surfaces for oxidation. The charge is heated by a gas flame on its surface. Oxidation of the charge supplies much of the reactive heat as the reaction progresses. A variety of products can be manufactured from pig lead feed by varying the feed temperature, and time of furnacing. Yellow litharge (orthorhombic) can be made by cooking for several hours at 600 to 700°C (1112 to 1292°F) but may contain traces of red lead and/or free metallic lead.

In the rotary tube furnace process, molten lead is introduced into the upper end of a refractory-lined inclined rotating tube. An oxidizing flame in the lower end maintains the desired temperature of reaction. The tube is long enough so that the charge is completely oxidized when it emerges from the lower end. This type of furnace has been used commonly to produce lead monoxide (tetragonal type), but it is not unusual for the final product to contain traces of both free metallic and red lead.

The Barton Pot process (Figure 7.16-1) uses a cast iron pot with an upper and lower stirrer rotating at different speeds. Molten lead is fed through a port in the cover into the pot, where it is broken up into droplets by high-speed blades. Heat is supplied initially to develop an operating temperature from 370 to 480°C (698 to 896°F). The exothermic heat from the resulting oxidation of the droplets is usually sufficient to maintain the desired temperature. The oxidized product is swept out of the pot by an air stream.

The operation is controlled by adjusting the rate of molten lead feed, the speed of the stirrers, the temperature of the system, and the rate of air flow through the pot. The Barton Pot produces either litharge or leady litharge (litharge with 50 percent free lead). Since it operates at a higher temperature than a ball mill unit, the oxide portion will usually contain some orthorhombic litharge. It may also be operated to obtain almost entirely orthorhombic product.

High Temperature Oxidation - High temperature oxidation is a fume-type process. A very fine particle, high-purity orthorhombic litharge is made by burning a fine stream of molten lead in a special blast-type burner. The flame temperature is around 1200°C (2192°F). The fume is swept out of the chamber by an air stream, cooled in a series of "goosenecks" and collected in a baghouse. The median particle diameter is from 0.50 to 1.0 microns, as compared with 3.0 to 16.0 microns for lead monoxide manufactured by other methods.

7.16.3 Emissions And Controls[3-4,6]

Emission factors for lead oxide and pigment production processes are given in Tables 7.16.3-1 and 7.16.3-2. The emission factors were assigned an E rating because of high variabilities in test run results and nonisokinetic sampling. Also, since Storage battery production facilities produce lead oxide using the Barton Pot process, a comparison of the lead emission factors from both industries has been performed. The lead oxide emission factors from the battery plants were found to be considerably lower than the emission factors from the lead oxide and pigment industry. Since lead battery production plants are covered under federal regulations, one would expect lower emissions from these sources.

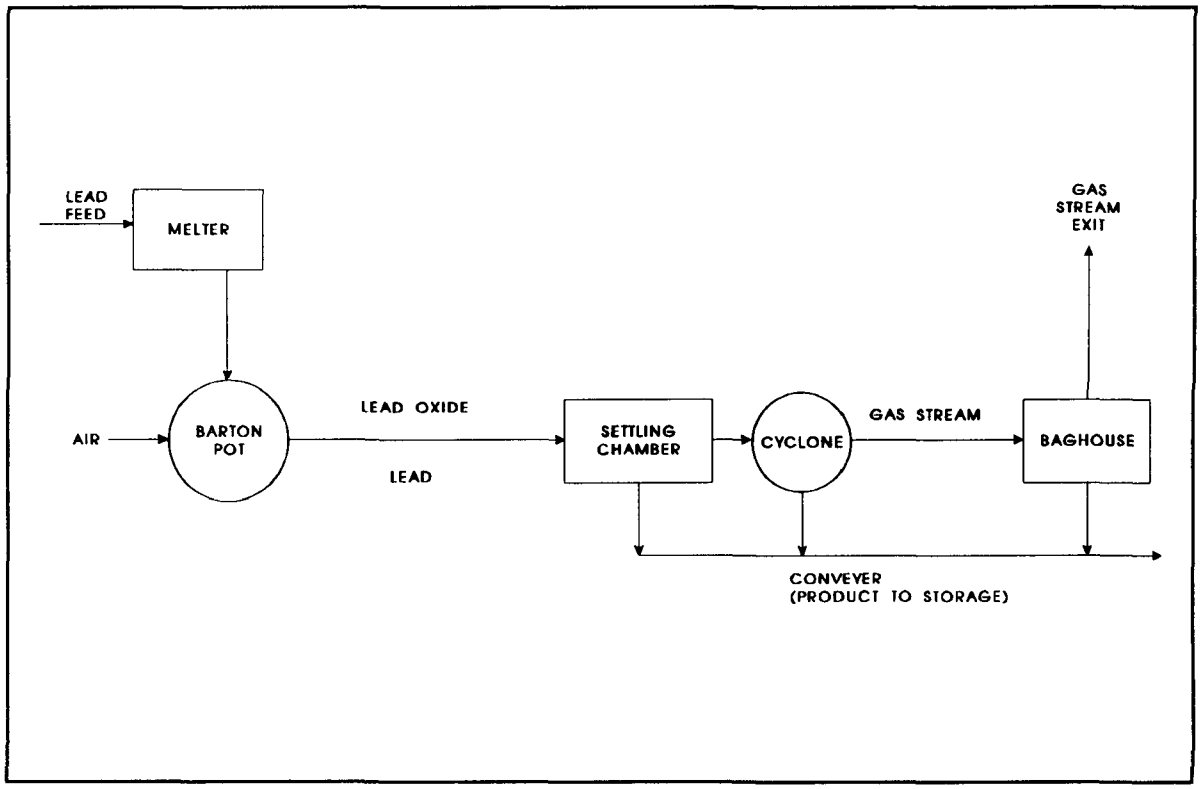


Figure 2.2.2-1. Lead oxide Barton Pot process.

Automatic shaker-type fabric filters, often preceded by cyclone mechanical collectors or settling chambers, are the common choice for collecting lead oxides and pigments. Control efficiencies of 99 percent are achieved with these control device combinations. Where fabric filters are not appropriate scrubbers may be used, to achieve control efficiencies from 70 to 95 percent. The ball mill and Barton Pot processes of black oxide manufacturing recover the lead product by these two means. Collection of dust and fumes from the production of red lead is likewise an economic necessity, since particulate emissions, although small, are about 90 percent lead. Emissions data from the production of white lead pigments are not available, but they have been estimated because of health and safety regulations. The emissions from dryer exhaust scrubbers account for over 50 percent of the total lead emitted in lead chromate production.

Table 7.16-1 (Metric Units).
CONTROLLED EMISSIONS FROM LEAD OXIDE AND PIGMENT PRODUCTION[a]

Process	Particulate		Lead		References
	Emissions	Emission Factor Rating	Emissions	Emission Factor Rating	
Lead Oxide Production					
Barton Pot[b] (SCC 3-01-035-06)	0.21 - 0.43	E	0.22	E	4,6
Calcining (SCC 3-01-035-07)					
Baghouse Inlet	7.13	E	7.00	E	6
Baghouse Outlet	0.032	E	0.024	E	6
Pigment Production					
Red lead[b] (SCC 3-01-035-10)	0.5[c]	B	0.50	B	4-5
White lead[b] (SCC 3-01-035-15)			0.28	B	4-5
Chrome pigments (SCC 3-01-035-20)			0.065	B	4-5

[a]Factors are for kg/Mg of product. SCC = Source Classification Code.
[b]Measured at baghouse outlet. Baghouse is considered process equipment.
[c]Only PbO and oxygen are used in red lead production, so particulate emissions are assumed to be about 90% lead.

Table 7.16-2 (English Units).
CONTROLLED EMISSIONS FROM LEAD OXIDE AND PIGMENT PRODUCTION[a]

Process	Particulate		Lead		References
	Emissions	Emission Factor Rating	Emissions	Emission Factor Rating	
Lead Oxide Production					
Barton Pot[b] (SCC 3-01-035-06)	0.43 - 0.85	E	0.44	E	4,6
Calcining (SCC 3-01-035-07)					
Baghouse Inlet	14.27	E	14.00	E	6
Baghouse Outlet	0.064	E	0.05	E	6
Pigment Production					
Red lead[b] (SCC 3-01-035-10)	1.0[c]	B	0.90	B	4-5
White lead[b] (SCC 3-01-035-15)			0.55	B	4-5
Chrome pigments (SCC 3-01-035-20)			0.13	B	4-5

[a]Factors are for lb/ton of product. SCC = Source Classification Code.
[b]Measured at baghouse outlet. Baghouse is considered process equipment.
[c]Only PbO and oxygen are used in red lead production, so particulate emissions are assumed to be about 90% lead.

References for Section 7.16

1. E. J. Ritchie, *Lead Oxides*, Independent Battery Manufacturers Association, Inc., Largo, FL, 1974.

2. W. E. Davis, *Emissions Study Of Industrial Sources Of Lead Air Pollutants, 1970*, EPA Contract No. 68-02-0271, W. E. Davis and Associates, Leawood, KS, April 1973.

3. *Background Information In Support Of The Development Of Performance Standards For The Lead Additive Industry,* EPA Contract No. 68-02-2085, PEDCo Environmental Specialists, Inc., Cincinnati, OH, January 1976.

4. *Control Techniques For Lead Air Emissions*, EPA-450/2-77-012A. U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1977.

5. R. P. Betz, *et al., Economics Of Lead Removal In Selected Industries*, EPA Contract No. 68-02-0299, Battelle Columbus Laboratories, Columbus OH, December 1972.

6. *Air Pollution Emission Test*, Contract No. 74-PB-0-1, Task No. 10, Office Of Air Quality Planning And Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, August 1973.

7. *Mineral Yearbook, Volume 1: Metals And Minerals*, Bureau Of Mines, U.S. Department Of The Interior, Washington, DC, 1989.

8. Harvey E. Brown, *Lead Oxide: Properties and Applications*, International Lead Zinc Research Organization, Inc., New York, NY, 1985.

8.8 CLAY AND FLY ASH SINTERING

NOTE: Clay and fly ash sintering operations are no longer conducted in the United States. However, this section is being retained for historical purposes.

8.8.1 Process Description[1-3]

Although the process for sintering fly ash and clay are similar, there are some distinctions that justify a separate discussion of each process. Fly ash sintering plants are generally located near the source, with the fly ash delivered to a storage silo at the plant. The dry fly ash is moistened with a water solution of lignin and agglomerated into pellets or balls. This material goes to a traveling-grate sintering machine where direct contact with hot combustion gases sinters the individual particles of the pellet and completely burns off the residual carbon in the fly ash. The product is then crushed, screened, graded, and stored in yard piles.

Clay sintering involves the driving off of entrained volatile matter. It is desirable that the clay contain a sufficient amount of volatile matter so that the resultant aggregate will not be too heavy. It is thus sometimes necessary to mix the clay with finely pulverized coke (up to 10 percent coke by weight). In the sintering process, the clay is first mixed with pulverized coke, if necessary, and then pelletized. The clay is next sintered in a rotating kiln or on a traveling grate. The sintered pellets are then crushed, screened, and stored, in a procedure similar to that for fly ash pellets.

8.8.2 Emissions and Controls[1]

In fly ash sintering, improper handling of the fly ash creates a dust problem. Adequate design features, including fly ash wetting systems and particulate collection systems on all transfer points and on crushing and screening operations, would greatly reduce emissions. Normally, fabric filters are used to control emissions from the storage silo, and emissions are low. The absence of this dust collection system, however, would create a major emission problem. Moisture is added at the point of discharge from silo to the agglomerator, and very few emissions occur there. Normally, there are few emissions from the sintering machine, but if the grate is not properly maintained, a dust problem is created. The consequent crushing, screening, handling, and storage of the sintered product also create dust problems.

In clay sintering, the addition of pulverized coke presents an emission problem because the sintering of coke-impregnated dry pellets produces more particulate emissions than the sintering of natural clay. The crushing, screening, handling, and storage of the sintered clay pellets creates dust problems similar to those encountered in fly-ash sintering. Emission factors for both clay and fly-ash sintering are shown in Table 8.8-1.

TABLE 8.8-1 (METRIC UNITS)
EMISSION FACTORS FOR CLAY AND FLY ASH SINTERING[a]

Source (SSC)	Filterable[b]				Condensible PM[c]			
	PM		PM-10		Inorganic		Organic	
	kg/Mg of Material	Emission Factor Rating	kg/Mg of Material	Emission Factor Rating	kg/Mg of Material	Emission Factor Rating	kg/Mg of Material	Emission Factor Rating
Fly ash crushing, screening, sintering, and storage (3-05-009-01)[d]	55	E	ND		ND		ND	
Clay/coke mixture sintering (3-05-009-02)[e]	20	E	ND		ND		ND	
Clay/coke mixture crushing, screening, and storage (3-05-009-07)[f]	7.5	E	ND		ND		ND	
Natural clay sintering (3-05-009-03)[g]	6	E	ND		ND		ND	
Natural clay crushing, screening, and storage (3-05-009-04)[f]	6	E	ND		ND		ND	

ND = No data.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
[c]Condensible PM is that PM collected in the impinger portion of a PM sampling train.
[d]Reference 1.
[e]References 3 to 5; for 90 percent clay, 10 percent pulverized coke; traveling grate, single pass, up-draft sintering machine.
[f]Based on data in Section 8.19-2.
[g]Reference 2; rotary dryer sinterer.

TABLE 8.8-1 (ENGISH UNITS)
EMISSION FACTORS FOR CLAY AND FLY ASH SINTERING[a]

Source (SSC)	Filterable[b]				Condensible PM[c]			
	PM		PM-10		Inorganic		Organic	
	lb/ton of Material	Emission Factor Rating	lb/ton of Material	Emission Factor Rating	lb/ton of Material	Emission Factor Rating	lb/ton of Material	Emission Factor Rating
Fly ash crushing, screening, sintering, and storage (3-05-009-01)[d]	110	E	ND		ND		ND	
Clay/coke mixture sintering (3-05-009-02)[e]	40	E	ND		ND		ND	
Clay/coke mixture crushing, screening, and storage (3-05-009-07)[f]	15	E	ND		ND		ND	
Natural clay sintering (3-05-009-03)[g]	12	E	ND		ND		ND	
Natural clay crushing, screening, and storage (3-05-009-04)[f]	12	E	ND		ND		ND	

ND = No data.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
[c]Condensible PM is that PM collected in the impinger portion of a PM sampling train.
[d]Reference 1.
[e]References 3 to 5; for 90 percent clay, 10 percent pulverized coke; traveling grate, single pass, up-draft sintering machine.
[f]Based on data in Section 8.19-2.
[g]Reference 2; rotary dryer sinterer.

References for Section 8.8

1. *Air Pollutant Emission Factors, Final Report*, Resources Research, Inc., VA. Prepared for National Air Pollution Control Administration, Durham, N.C., under Contract No. (PA-22-68-119). April 1970.

2. Communication between Resources Research, Inc., Reston, VA, and a clay sintering firm. October 2, 1969.

3. Communication between Resources Research, Inc., Reston, VA., and an anonymous Air Pollution Control Agency. October 16, 1969.

4. J. J. Henn, *et al.*, *Methods for Producing Alumina from Clay: An Evaluation of Two Lime Sinter Processes*, Department of the Interior, U. S. Bureau of Mines. Washington, DC, Report of Investigation No. 7299. September 1969.

5. F. A. Peters, *et al.*, *Methods for Producing Alumina from Clay: An Evaluation of the Lime-Soda Sinter Process*, Department of the Interior, U. S. Bureau of Mines, Washington, DC. Report of Investigation No. 6927. 1967.

8.10 CONCRETE BATCHING

8.10-1 Process Description[1-4]

Concrete is composed essentially of water, cement, sand (fine aggregate) and coarse aggregate. Coarse aggregate may consist of gravel, crushed stone or iron blast furnace slag. Some specialty aggregate products could be either heavyweight aggregate (of barite, magnetite, limonite, ilmenite, iron or steel) or lightweight aggregate (with sintered clay, shale, slate, diatomaceous shale, perlite, vermiculite, slag, pumice, cinders, or sintered fly ash). Concrete batching plants store, convey, measure and discharge these constituents into trucks for transport to a job site. In some cases, concrete is prepared at a building construction site or for the manufacture of concrete products such as pipes and prefabricated construction parts. Figure 8.10-1 is a generalized process diagram for concrete batching.

The raw materials can be delivered to a plant by rail, truck or barge. The cement is transferred to elevated storage silos pneumatically or by bucket elevator. The sand and coarse aggregate are transferred to elevated bins by front end loader, clam shell crane, belt conveyor, or bucket elevator. From these elevated bins, the constituents are fed by gravity or screw conveyor to weigh hoppers, which combine the proper amounts of each material.

Truck mixed (transit mixed) concrete involves approximately 75 percent of U. S. concrete batching plants. At these plants, sand, aggregate, cement and water are all gravity fed from the weigh hopper into the mixer trucks. The concrete is mixed on the way to the site where the concrete is to be poured. Central mix facilities (including shrink mixed) constitute the other one fourth of the industry. With these, concrete is mixed and then transferred to either an open bed dump truck or an agitator truck for transport to the job site. Shrink mixed concrete is concrete that is partially mixed at the central mix plant and then completely mixed in a truck mixer on the way to the job site. Dry batching, with concrete mixed and hauled to the construction site in dry form, is seldom, if ever, used.

8.10-2 Emissions and Controls[5-7]

Emission factors for concrete batching are given in Tables 8.10-1 and 8.10-2, with potential air pollutant emission points shown. Particulate matter, consisting primarily of cement dust but including some aggregate and sand dust emissions, is the only pollutant of concern. All but one of the emission points are fugitive in nature. The only point source is the transfer of cement to the silo, and this is usually vented to a fabric filter or "sock". Fugitive sources include the transfer of sand and aggregate, truck loading, mixer loading, vehicle traffic, and wind erosion from sand and aggregate storage piles. The amount of fugitive emissions generated during the transfer of sand and aggregate depends primarily on the surface moisture content of these materials. The extent of fugitive emission control varies widely from plant to plant.

Types of controls used may include water sprays, enclosures, hoods, curtains, shrouds, movable and telescoping chutes, and the like. A major source of potential emissions, the movement of heavy trucks over unpaved or dusty surfaces in and around the plant, can be controlled by good maintenance and wetting of the road surface.

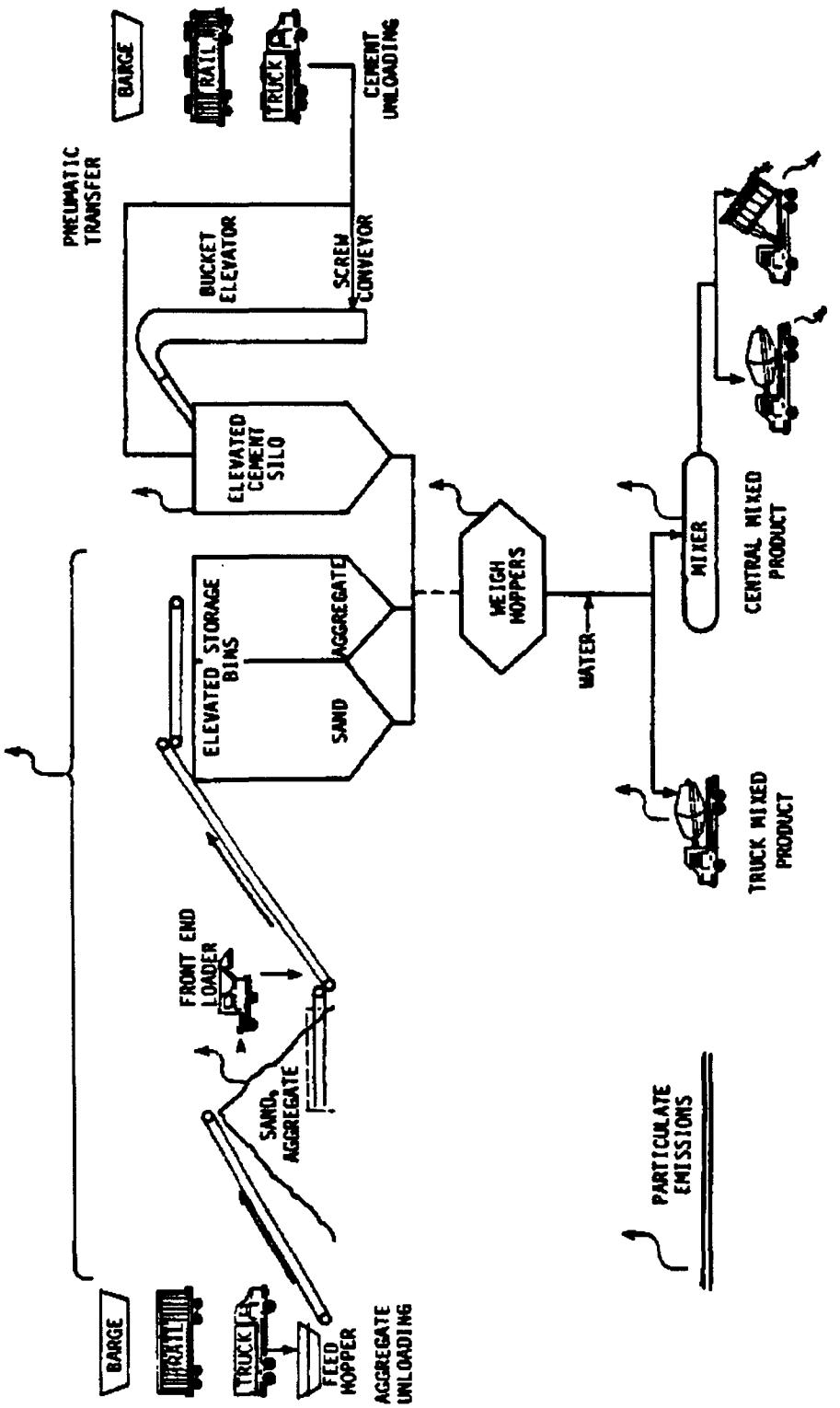


Figure 8.1-1. Typical concrete batching process.

TABLE 8.10-1 (METRIC UNITS)
EMISSION FACTORS FOR CONCRETE BATCHING[a]

All Emission Factors in kg/Mg of Material Mixed Unless Noted
Ratings (A-E) Follow Each Emission Factor

Source (SSC)	Filterable[b]			Condensible PM[c]	
	PM		PM-10	Inorganic	Organic
Sand and aggregate transfer to elevated bin (3-05-011-06)[d]	0.014	E	ND	ND	ND
Cement unloading to elevated storage silo					
Pneumatic[e]	0.13	D	ND	ND	ND
Bucket elevator[f] (3-05-011-07)	0.12	E	ND	ND	ND
Weigh hopper loading (3-05-011-08)[g]	0.01	E	ND	ND	ND
Mixer loading (central mix) (3-05-011-09)[g]	0.02	E	ND	ND	ND
Truck loading (truck mix) (3-05-011-10[g]	0.01	E	ND	ND	ND
Vehicle traffic (unpaved roads) (3-05-011-__)[h]	4.5	C	ND	ND	ND
Wind erosion from sand and aggregate storage piles (3-05-011-__)[i]	3.9	D	ND	ND	ND
Total process emissions (truck mix) (3-05-011-__)[j]	0.05	E	ND	ND	ND

ND = No data.

[a]Factors represent uncontrolled emissions unless otherwise noted.

[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

[c]Condensible PM is that PM collected in the impinger portion of a PM sampling train.

[d]Reference 6.

[e]For uncontrolled emissions measured before filter. Based on two tests on pneumatic conveying controlled by a fabric filter.

[f]Reference 7. From test of mechanical unloading to hopper and subsequent transport of cement by enclosed bucket elevator to elevated bins with fabric socks over bin vent.

[g]Reference 5. Engineering judgement, based on observations and emissions tests of similar controlled sources.

[h]From Section 11.2.1, with k = 0.8, s = 12, S = 20, W = 20, w = 14, and p = 100; units of kg/vehicle kilometers traveled.

[i]From Section 8.19.1, for emissions <30 micrometers from inactive storage piles; units of kg/hectare/day

[j]Based on pneumatic conveying of cement at a truck mix facility. Does not include vehicle traffic or wind erosion from storage piles.

Table 8.10-2 (English Units)
EMISSION FACTORS FOR CONCRETE BATCHING[a]

All Emission Factors in the lb/ton (lb/yd^3) of Material Mixed Unless Noted[b]
Ratings (A-E) Follow Each Emission Factor

Source (SSC)	Filterable[c]			Condensible PM[d]	
	PM		PM-10	Inorganic	Organic
Sand and aggregate transfer to elevated bin (3-05-011-06)[e]	0.029 (0.05)	E	ND	ND	ND
Cement unloading to elevated storage silo					
Pneumatic[f]	0.27 (0.07)	D	ND	ND	ND
Bucket elevator[g] (3-05-011-07)	0.24 (0.06)	E	ND	ND	ND
Weigh hopper loading (3-05-011-08)[h]	0.02 (0.04)	E	ND	ND	ND
Mixer loading (central mix) (3-05-011-09)[h]	0.04 (0.07)	E	ND	ND	ND
Truck loading (truck mix) (3-05-011-10[h]	0.02 (0.04)	E	ND	ND	ND
Vehicle traffic (unpaved roads) (3-05-011-__)[i]	16 (0.02)	C	ND	ND	ND
Wind erosion from sand and aggregate storage piles (3-05-011-__)[j]	3.5[k] (0.1)[l]	D	ND	ND	ND
Total process emissions (truck mix) (3-05-011-__)[m]	0.1 (0.2)	E	ND	ND	ND

ND = No data.

[a]Factors represent uncontrolled emissions unless otherwise noted.

[b]Based on a typical yd^3 weighing 1.818 kg (4,000 lb) and containing 227 kg (500 lb) cement, 564 kg (1,240 lb) sand, 864 kg (1,900 lb) coarse aggregate and 164 kg (360 lb) water.

[c]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

[d]Condensible PM is that PM collected in the impinger portion of a PM sampling train.

[e]Reference 6.

[f]For uncontrolled emissions measured before filter. Based on two tests on pneumatic conveying controlled by a fabric filter.

[g]Reference 7. From test of mechanical unloading to hopper and subsequent transport of cement by enclosed bucket elevator to elevated bins with fabric socks over bin vent.

[h]Reference 5. Engineering judgement, based on observations and emission tests of similar controlled sources.

[i]From Section 11.2.1, with k = 0.8, s = 12, S = 20, W = 20, w = 14, and p = 100; units of lb/vehicle miles traveled; based on facility producing 23,100 m^3/yr (30,000 yd^3/yr) of concrete, with average truck load of 6.2 m^3 (8 yd^3) and plant road length of 161 meters (0.1 mile).

[j]From Section 8.19.1, for emissions <30 micrometers from inactive storage piles.

[k]Units of lb/acre/day.

[l]Assumes 1,011 m^2 (1/4 acre) of sand and aggregate storage at plant with production of 23,000 m^3/yr (30,000 yr^3/yr).

[m]Based on pneumatic conveying of cement at a truck mix facility; does not include vehicle traffic or wind erosion from storage piles.

Predictive equations that allow for emission factor adjustment based on plant specific conditions are given in Chapter 11. Whenever plant specific data are available, they should be used in lieu of the fugitive emission factors presented in Table 8.10-1.

References for Section 8.10

1. *Air Pollutant Emission Factors*, APTD-0923, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1970.

2. *Air Pollution Engineering Manual*, 2nd Edition, AP-40, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1974. Out of Print.

3. Telephone and written communication between Edwin A. Pfetzing, PEDCo Environmental., Inc., Cincinnati, OH, and Richard Morris and Richard Meininger, National Ready Mix Concrete Association, Silver Spring, MD, May 1984.

4. *Development Document for Effluent Limitations Guidelines and Standards of Performance, The Concrete Products Industries, Draft*, U. S. Environmental Protection Agency, Washington, DC, August 1975.

5. *Technical Guidance for Control of Industrial Process Fugitive Particulate Emissions*, EPA-450/3-77-010, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1977.

6. *Fugitive Dust Assessment at Rock and Sand Facilities in the South Coast Air Basin*, Southern California Rock Products Association and Southern California Ready Mix Concrete Association, Santa Monica, CA, November 1979.

7. Telephone communication between T. R. Blackwood, Monsanto Research Corp., Dayton, OH, and John Zoller, Pedco Environmental, Inc., Cincinnati, OH, October 18, 1976.

8.11 GLASS FIBER MANUFACTURING

8.11.1 General[1-4]

Glass fiber manufacturing is the high-temperature conversion of various raw materials (predominantly borosilicates) into a homogeneous melt, followed by the fabrication of this melt into glass fibers. The two basic types of glass fiber products, textile and wool, are manufactured by similar processes. A typical diagram of these processes is shown in Figure 8.11-1. Glass fiber production can be segmented into three phases: raw materials handling, glass melting and refining, and wool glass fiber forming and finishing, this last phase being slightly different for textile and wool glass fiber production.

Raw Materials Handling - The primary component of glass fiber is sand, but it also includes varying quantities of feldspar, sodium sulfate, anhydrous borax, boric acid, and many other materials. The bulk supplies are received by rail car and truck, and the lesser-volume supplies are received in drums and packages. These raw materials are unloaded by a variety of methods, including drag shovels, vacuum systems, and vibrator/gravity systems. Conveying to and from storage piles and silos is accomplished by belts, screws, and bucket elevators. From storage, the materials are weighed according to the desired product recipe and then blended well before their introduction into the melting unit. The weighing, mixing, and charging operations may be conducted in either batch or continuous mode.

Glass Melting and Refining - In the glass melting furnace, the raw materials are heated to temperatures ranging from 1500° to 1700°C (2700° to 3100°F) and are transformed through a sequence of chemical reactions to molten glass. Although there are many furnace designs, furnaces are generally large, shallow, and well-insulated vessels that are heated from above. In operation, raw materials are introduced continuously on top of a bed of molten glass, where they slowly mix and dissolve. Mixing is effected by natural convection, gases rising from chemical reactions, and, in some operations, by air injection into the bottom of the bed.

Glass melting furnaces can be categorized, by their fuel source and method of heat application, into four types: recuperative, regenerative, unit, and electric melter. The recuperative, regenerative, and unit melter furnaces can be fueled by either gas or oil. The current trend is from gas-fired to oil-fired. Recuperative furnaces use a steel heat exchanger, recovering heat from the exhaust gases by exchange with the combustion air. Regenerative furnaces use a lattice of brickwork to recover waste heat from exhaust gases. In the initial mode of operation, hot exhaust gases are routed through a chamber containing a brickwork lattice, while combustion air is heated by passage through another corresponding brickwork lattice. About every 20 minutes, the airflow is reversed, so that the combustion air is always being passed through hot brickwork previously heated by exhaust gases. Electric furnaces melt glass by passing an electric current through the melt. Electric furnaces are either hot-top or cold-top. The former use gas for auxiliary heating, and the latter use only the electric current. Electric furnaces are currently used only for wool glass fiber production because of the electrical properties of the glass formulation. Unit melters are used only for the "indirect" marble melting process, getting raw materials from a continuous screw at the back of the furnace adjacent to the exhaust air discharge. There are no provisions for heat recovery with unit melters.

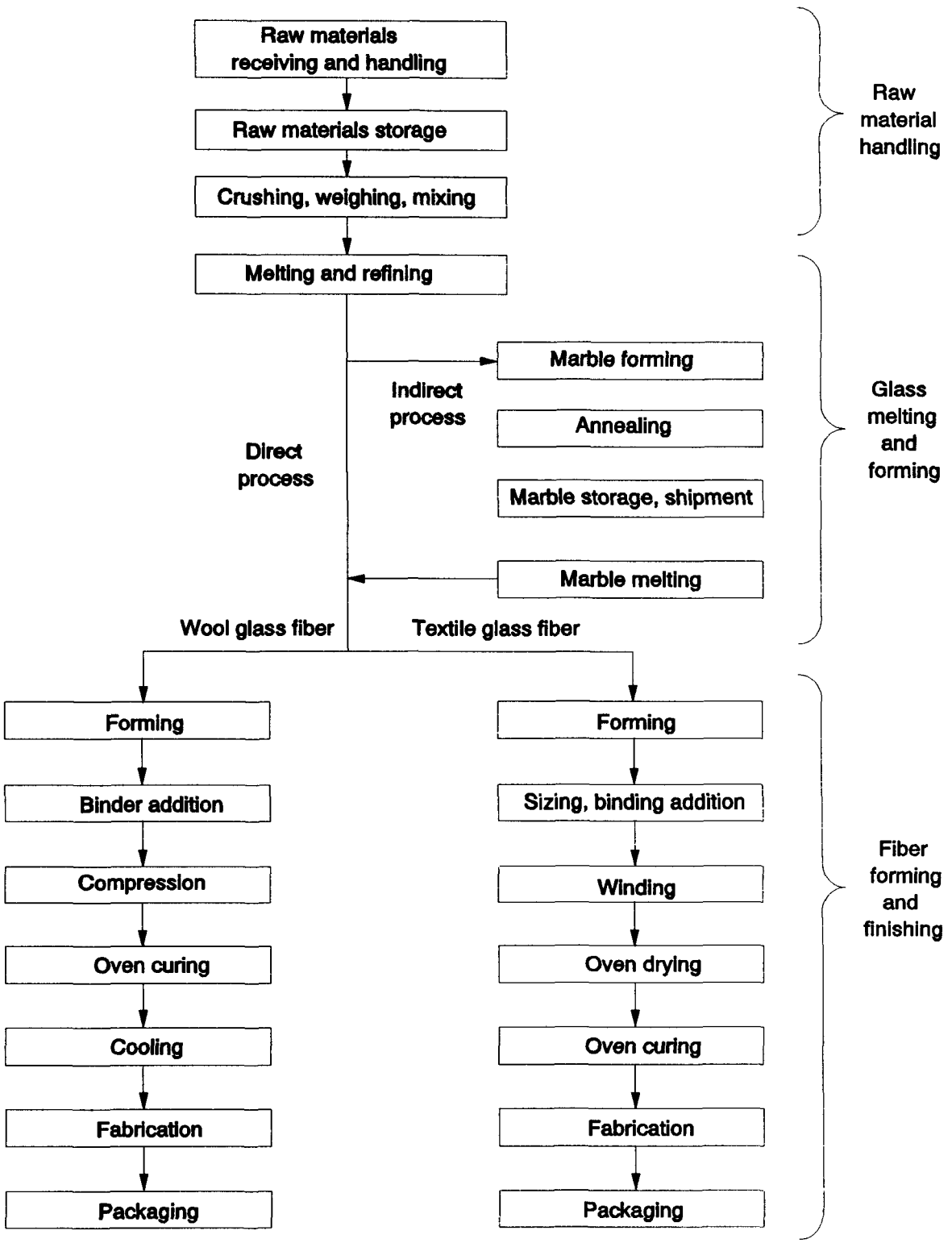


Figure 8.11-1. Typical flow diagram of the glass fiber production process.

In the "indirect" melting process, molten glass passes to a forehearth, where it is drawn off, sheared into globs, and formed into marbles by roll-forming. The marbles are then stress-relieved in annealing ovens, cooled, and conveyed to storage or to other plants for later use. In the "direct" glass fiber process, molten glass passes from the furnace into a refining unit, where bubbles and particles are removed by settling, and the melt is allowed to cool to the proper viscosity for the fiber forming operation.

Wool Glass Fiber Forming and Finishing - Wool fiberglass is produced for insulation and is formed into mats that are cut into batts. (Loose wool is primarily a waste product formed from mat trimming, although some is a primary product, and is only a small part of the total wool fiberglass produced. No specific emission data for loose wool production are available.) The insulation is used primarily in the construction industry and is produced to comply with ASTM C167-64, the "Standard Test Method for Thickness and Density of Blanket- or Batt-Type Thermal Insulating Material."

Wool fiberglass insulation production lines usually consist of the following processes: (1) preparation of molten glass, (2) formation of fibers into a wool fiberglass mat, (3) curing the binder-coated fiberglass mat, (4) cooling the mat, and (5) backing, cutting, and packaging the insulation. Fiberglass plants contain various sizes, types, and numbers of production lines, although a typical plant has three lines. Backing (gluing a flat flexible material, usually paper, to the mat), cutting, and packaging operations are not significant sources of emissions to the atmosphere.

The trimmed edge waste from the mat and the fibrous dust generated during the cutting and packaging operations are collected by a cyclone and either are transported to a hammer mill to be chopped into blown wool (loose insulation) and bulk packaged or are recycled to the forming section and blended with newly formed product.

During the formation of fibers into a wool fiberglass mat (the process known as "forming" in the industry), glass fibers are made from molten glass, and a chemical binder is simultaneously sprayed on the fibers as they are created. The binder is a thermosetting resin that holds the glass fibers together. Although the binder composition varies with product type, typically the binder consists of a solution of phenol-formaldehyde resin, water, urea, lignin, silane, and ammonia. Coloring agents may also be added to the binder. Two methods of creating fibers are used by the industry. In the rotary spin process, depicted in Figure 8.11-2, centrifugal force causes molten glass to flow through small holes in the wall of a rapidly rotating cylinder to create fibers that are broken into pieces by an air stream. This is the newer of the two processes and dominates the industry today. In the flame attenuation process, molten glass flows by gravity from a furnace through numerous small orifices to create threads that are then attenuated (stretched to the point of breaking) by high velocity, hot air, and/or a flame. After the glass fibers are created (by either process) and sprayed with the binder solution, they are collected by gravity on a conveyor belt in the form of a mat.

The conveyor carries the newly formed mat through a large oven to cure the thermosetting binder and then through a cooling section where ambient air is drawn down through the mat. Figure 8.11-3 presents a schematic drawing of the curing and cooling sections. The cooled mat remains on the conveyor for trimming of the uneven edges. Then, if product specifications require it, a backing is applied with an adhesive to form a vapor barrier. The mat is then cut into batts of the desired dimensions and packaged.

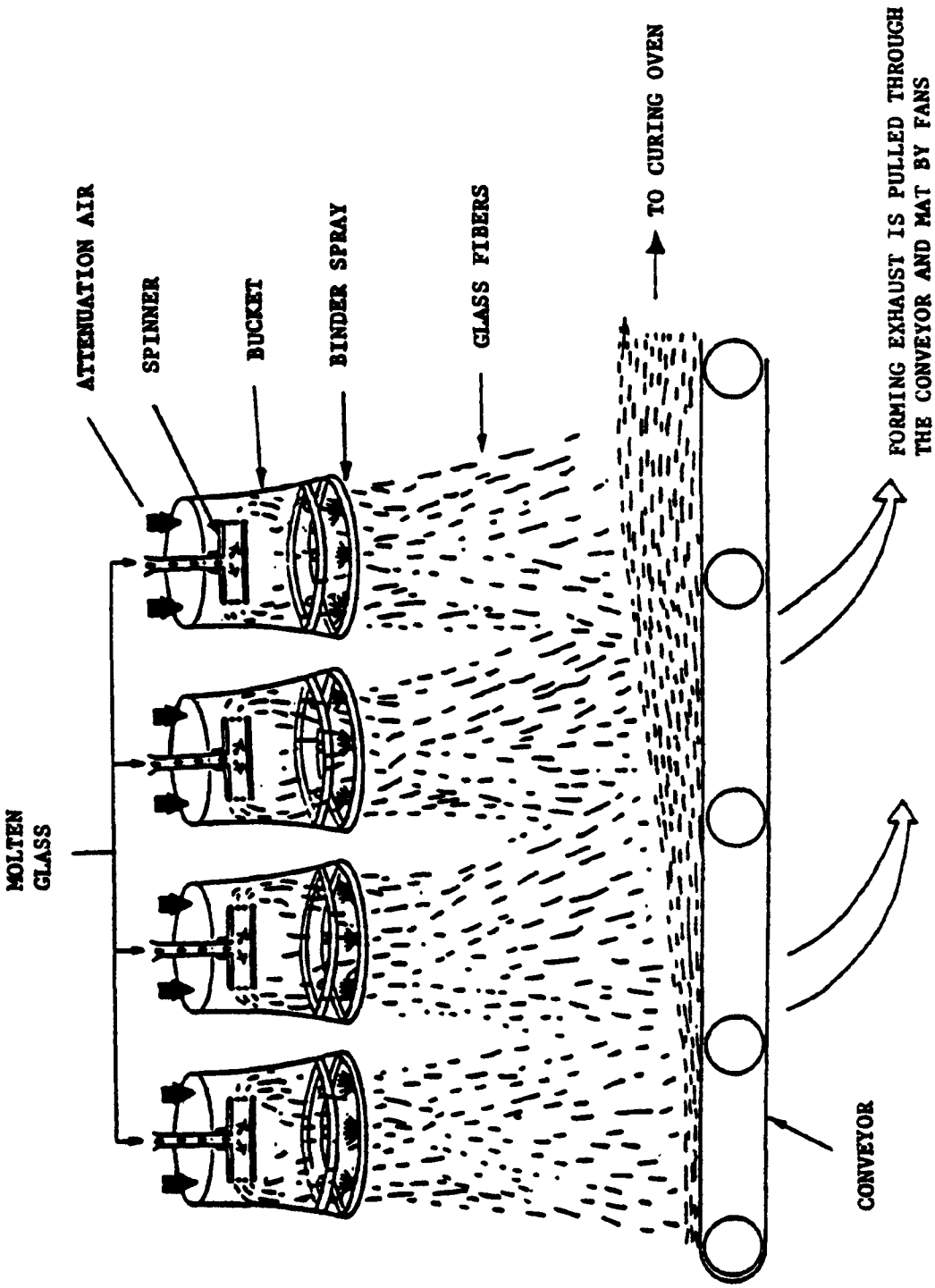


Figure 8.11.2. A typical spin process.

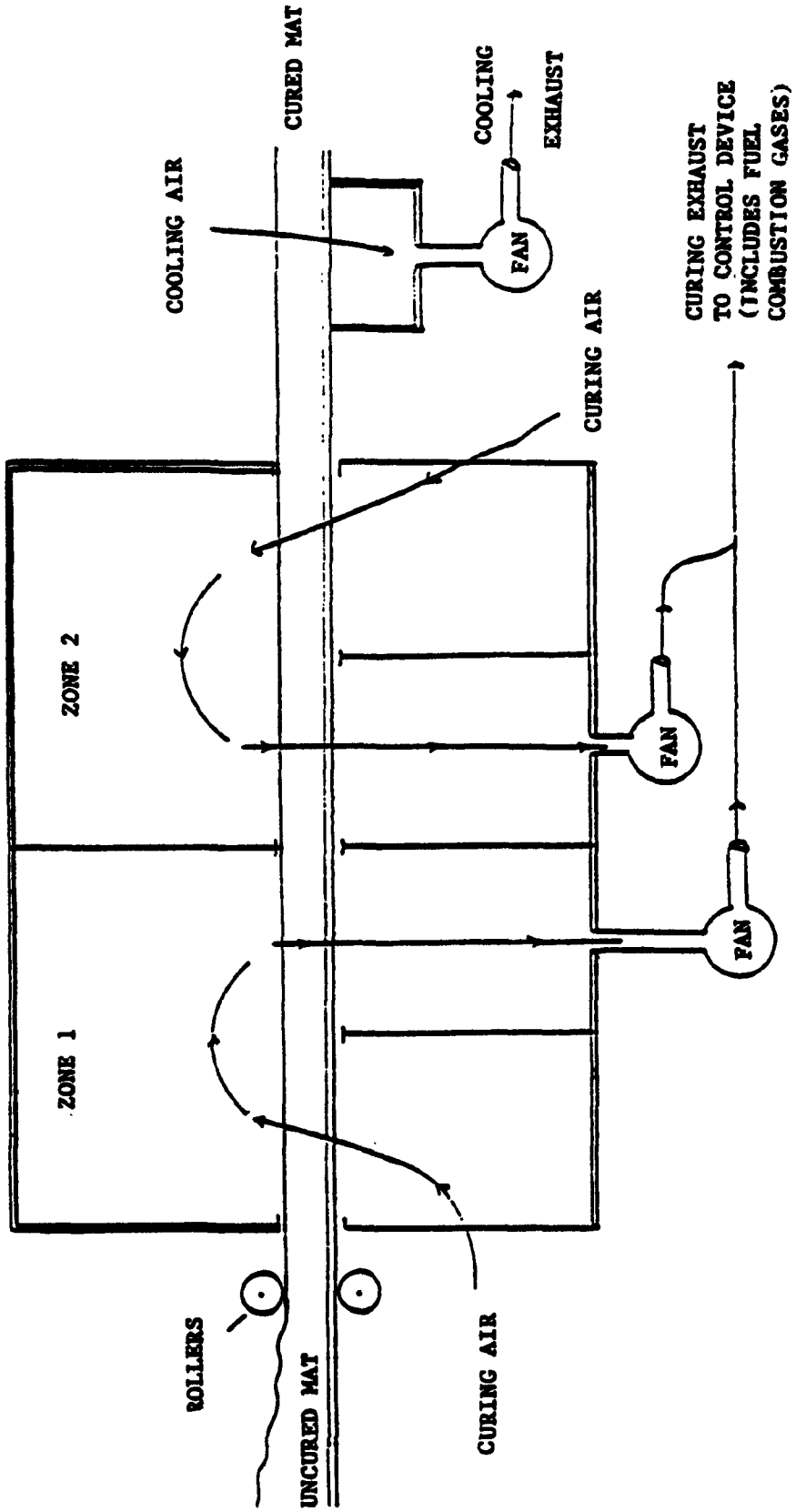


Figure 8.11-3. Side view of curing oven (indirect heating) and cooling section.

Textile Glass Fiber Forming and Finishing - Molten glass from either the direct melting furnace or the indirect marble melting furnace is temperature-regulated to a precise viscosity and delivered to forming stations. At the forming stations, the molten glass is forced through heated platinum bushings containing numerous very small openings. The continuous fibers emerging from the openings are drawn over a roller applicator, which applies a coating of a water-soluble sizing and/or coupling agent. The coated fibers are gathered and wound into a spindle. The spindles of glass fibers are next conveyed to a drying oven, where moisture is removed from the sizing and coupling agents. The spindles are then sent to an oven to cure the coatings. The final fabrication includes twisting, chopping, weaving, and packaging the fiber.

8.11.2 Emissions and Controls[1,3,4]

Emissions and controls for glass fiber manufacturing can be categorized by the three production phases with which they are associated. Emission factors for the glass fiber manufacturing industry are given in Tables 8.11-1 through 8.11-3.

Raw Materials Handling - The major emissions from the raw materials handling phase are fugitive dust and raw material particles generated at each of the material transfer points. Such a point would be where sand pours from a conveyor belt into a storage silo. The two major control techniques are wet or moist handling and fabric filters. When fabric filters are used, the transfer points are enclosed, and air from the transfer area is continuously circulated through the fabric filters.

Glass Melting and Refining - The emissions from glass melting and refining include volatile organic compounds from the melt, raw material particles entrained in the furnace flue gas, and, if furnaces are heated with fossil fuels, combustion products. The variation in emission rates among furnaces is attributable to varying operating temperatures, raw material compositions, fuels, and flue gas flow rates. Of the various types of furnaces used, electric furnaces generally have the lowest emission rates, because of the lack of combustion products and of the lower temperature of the melt surface caused by bottom heating. Emission control for furnaces is primarily fabric filtration. Fabric filters are effective on particulate matter (PM) and sulfur oxides (SO_x) and, to a lesser extent, on carbon monoxide (CO), nitrogen oxides (NO_x), and fluorides. The efficiency of these compounds is attributable to both condensation on filterable PM and chemical reaction with PM trapped on the filters. Reported fabric filter efficiencies on regenerative and recuperative wool furnaces are for PM, 95+ percent; SO_x, 99+ percent; CO, 30 percent; and fluoride, 91 to 99 percent. Efficiencies on other furnaces are lower because of lower emission loading and pollutant characteristics.

Wool Fiber Forming and Finishing - Emissions generated during the manufacture of wool fiberglass insulation include solid particles of glass and binder resin, droplets of binder, and components of the binder that have vaporized. Glass particles may be entrained in the exhaust gas stream during forming, curing, or cooling operations. Test data show that approximately 99 percent of the total emissions from the production line are emitted from the forming and curing sections. Even though cooling emissions are negligible at some plants, cooling emissions at others may include fugitives from the curing section. This commingling of emissions occurs because fugitive emissions from the open terminal end of the curing oven may be induced into the cooling exhaust ductwork and be discharged into the atmosphere. Solid particles of resin may be entrained in the gas stream in either the curing or cooling sections. Droplets of organic binder may be entrained in the gas stream in the forming section or may be a result of condensation of gaseous pollutants as the gas stream is cooled. Some of the liquid binder used in the forming section is vaporized by the elevated temperatures in the forming and curing processes. Much of the vaporized material will condense

Table 8.11-1 (Metric Units)
EMISSION FACTORS FOR GLASS FIBER MANUFACTURING[a]

Source (SSC)	Filterable[b]				Condensible PM[c]		
	PM		PM-10		Inorganic	Organic	
	kg/Mg of Material Processed	Emission Factor Rating	kg/Mg of Material Processed	Emission Factor Rating	kg/Mg of Material Processed	kg/Mg of Material Processed	Emission Factor Rating
Unloading and conveying (3-05-021-21)[d]	1.5	B	ND		ND	ND	
Storage bins (3-05-021-22)[d]	0.1	B	ND		ND	ND	
Mixing and weighing (3-05-021-23)[d]	0.3	B	ND		ND	ND	
Crushing and batch charging (3-05-021-24)[d]	Neg.		ND		ND	ND	
Glass furnace--wool[e]							
Electric (3-05-021-03)	0.25	B	ND		ND	ND	
Gas--regenerative (3-05-021-01)	11	B	ND		ND	ND	
Gas--recuperative (3-05-021-02)	13-15	B	ND		ND	ND	
Gas--unit melter (3-05-021-07)	4.5	B	ND		ND	ND	
Glass furnace--textile[e]							
Gas--regenerative (3-05-021-11)	1	B	ND		ND	ND	
Gas--recuperative (3-05-021-12)	8	B	ND		ND	ND	
Gas--unit melter (3-05-021-13)	3	B	ND		ND	ND	
Forming--wool							
Flame attenuation (3-05-021-08)[e]	1	B	ND		ND	ND	
Forming--textile (3-05-021-14)[e]	0.5	B	ND		ND	ND	
Oven curing--wool							
Flame attenuation (3-05-021-09)[e]	3	B	ND		ND	ND	
Oven curing and cooling--textile (3-05-021-15)[e]	0.6		ND		ND	ND	

Table 8.11-1 (Metric Units) (Continued)
EMISSION FACTORS FOR GLASS FIBER MANUFACTURING[a]

Source (SSC)	Filterable[b]				Condensible PM[c]		
	PM		PM-10		Inorganic	Organic	
	kg/Mg of Material Processed	Emission Factor Rating	kg/Mg of Material Processed	Emission Factor Rating	kg/Mg of Material Processed	kg/Mg of Material Processed	Emission Factor Rating
Rotary spin wool glass manufacturing (3-05-021-04)[f]							
R-19	17.81	B	ND		ND	4.25	B
R-11	19.61	B	ND		ND	3.19	B
Ductboard	27.72	B	ND		ND	8.55	B
Heavy density	4.91	B	ND		ND	1.16	B

ND = No data.
Neg. = Negligible.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
[c]Condensible PM is that PM collected in the impinger portion of a PM sampling train.
[d]Reference 1.
[e]Reference 5.
[f]Reference 4; expressed in kg/Mg of finished product.

Table 8.11-2 (English Units)
EMISSION FACTORS FOR GLASS FIBER MANUFACTURING[a]

Source (SSC)	Filterable[b]				Condensible PM		
	PM		PM-10		Inorganic	Organic	
	lb/ton of Material Processed	Emission Factor Rating	lb/ton of Material Processed	Emission Factor Rating	lb/ton of Material Processed	lb/ton of Material Processed	Emission Factor Rating
Unloading and conveying (3-05-021-21)[d]	3.0	B	ND		ND	ND	
Storage bins (3-05-021-22)[d]	0.2	B	ND		ND	ND	
Mixing and weighing (3-05-021-23)[d]	0.6	B	ND		ND	ND	
Crushing and batch charging (3-05-021-24)[d]	Neg.		ND		ND	ND	
Glass furnace--wool[e]							
Electric (3-05-021-03)	0.5	B	ND		ND	ND	
Gas--regenerative (3-05-021-01)	22	B	ND		ND	ND	
Gas--recuperative (3-05-021-02)	25-30	B	ND		ND	ND	
Gas--unit melter (3-05-021-07)	9	B	ND		ND	ND	
Glass furnace--textile[e]							
Gas--regenerative (3-05-021-11)	2	B	ND		ND	ND	
Gas--recuperative (3-05-021-12)	16	B	ND		ND	ND	
Gas--unit melter (3-05-021-13)	6	B	ND		ND	ND	
Forming--wool							
Flame attenuation (3-05-021-08)[e]	2	B	ND		ND	ND	
Forming--textile (3-05-021-14)[e]	1	B	ND		ND	ND	
Oven curing--wool							
Flame attenuation (3-05-021-09)[e]	6	B	ND		ND	ND	
Oven curing and cooling--textile (3-05-021-15)[e]	1.2	B	ND		ND	ND	

Table 8.11-2 (English Units) (Continued)
EMISSION FACTORS FOR GLASS FIBER MANUFACTURING[a]

Source (SSC)	Filterable[b]				Condensible PM		
	PM		PM-10		Inorganic	Organic	
	lb/ton of Material Processed	Emission Factor Rating	lb/ton of Material Processed	Emission Factor Rating	lb/ton of Material Processed	lb/ton of Material Processed	Emission Factor Rating
Rotary spin wool glass manufacturing (3-05-021-04)[f]							
R-19	36.21	B	ND		ND	8.52	B
R-11	39.21	B	ND		ND	6.37	B
Ductboard	55.42	B	ND		ND	17.08	B
Heavy density	9.81	B	ND		ND	2.33	B

ND = No data.
Neg. = Negligible.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
[c]Condensible PM is that PM collected in the impinger portion of a PM sampling train.
[d]Reference 1.
[e]Reference 5.
[f]Reference 4; expressed in lb/ton of finished product.

Table 8.11-3 (Metric Units)
EMISSION FACTORS FOR GLASS FIBER MANUFACTURING[a]

Source (SCC)	SO_x		NO_x		CO	
	kg/Mg of Material Processed	Emission Factor Rating	kg/Mg of Material Processed	Emission Factor Rating	kg/Mg of Material Processed	Emission Factor Rating
Glass furnace--wool[b]						
Electric (3-05-021-03)	0.02	B	0.14	B	0.025	B
Gas--regenerative (3-05-021-01)	5	B	2.5	B	0.13	B
Gas--recuperative (3-05-021-02)	5	B	0.85	B	0.13	B
Gas--unit melter (3-05-021-07)	0.3	B	0.15	B	0.13	B
Glass furnace--textile[b]						
Gas--regenerative (3-05-021-11)	1.5	B	10	B	0.25	B
Gas--recuperative (3-05-021-12)	15	B	10	B	0.5	B
Gas--unit melter (3-05-021-13)	ND		10	B	0.45	B
Forming--wool[b]						
Flame attenuation (3-05-021-08)	NA		NA		NA	
Forming--textile[b] (3-05-021-14)	NA		NA		NA	
Oven curing--wool[b]						
Flame attenuation (3-05-021-09)	ND		1	B	1.8	B
Oven curing and cooling--textile[b] (3-05-021-15)	NA		1.3	B	0.75	B

ND = No data.
NA = Not applicable.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Reference 5.

TABLE 8.11-4 (ENGLISH UNITS)
EMISSION FACTORS FOR GLASS FIBER MANUFACTURING[a]

Source (SCC)	SO_x		NO_x		CO	
	lb/ton of Material Processed	Emission Factor Rating	lb/ton of Material Processed	Emission Factor Rating	lb/ton of Material Processed	Emission Factor Rating
Glass furnace--wool						
Electric (3-05-021-03)[b]	0.04	B	0.27	B	0.05	B
Gas--regenerative (3-05-021-01)	10	B	5	B	0.25	B
Gas--recuperative (3-05-021-02)	10	B	1.7	B	0.25	B
Gas--unit melter (3-05-021-07)	0.6	B	0.3	B	0.25	B
Glass furnace--textile						
Gas--regenerative (3-05-021-11)[b]	3	B	20	B	0.5	B
Gas--recuperative (3-05-021-12)	30	B	20	B	1	B
Gas--unit melter (3-05-021-13)	ND		20	B	0.9	B
Forming--wool						
Flame attenuation (3-05-021-08)[b]	NA		NA		NA	
Forming--textile (3-05-021-14)[b]	NA		NA		NA	
Oven curing--wool						
Flame attenuation (3-05-021-09)[b]	ND		2	B	3.5	B
Oven curing and cooling--textile (3-05-021-15)[b]	NA		2.6	B	1.5	B

ND = No data.
NA = Not applicable.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Reference 5.

Table 8.11-5 (Metric Units)
EMISSION FACTORS FOR GLASS FIBER MANUFACTURING[a]

Source (SCC)	VOC		Phenolics		Phenol		Formaldehyde		Fluorides	
	kg/Mg of Material Processed	Emission Factor Rating	kg/Mg of Material Processed	Emission Factor Rating	kg/Mg of Material Processed	Emission Factor Rating	kg/Mg of Material Processed	Emission Factor Rating	kg/Mg of Material Processed	Emission Factor Rating
Glass furnace--wool										
Electric (3-05-021-03)[b]	ND		ND		ND		ND		0.001	B
Gas--regenerative (3-05-021-01)	ND		ND		ND		ND		0.06	B
Gas--recuperative (3-05-021-02)	ND		ND		ND		ND		0.06	B
Gas--unit melter (3-05-021-07)	ND		ND		ND		ND		0.06	B
Glass furnace--textile[b]										
Gas--regenerative (3-05-021-11)	ND		ND		ND		ND		1	B
Gas--recuperative (3-05-021-12)	ND		ND		ND		ND		1	B
Gas--unit melter (3-05-021-13)	ND		ND		ND		ND		1	B
Forming--wool										
Flame attenuation (3-05-021-08)[b]	0.15	B	ND		ND		ND		ND	
Forming--textile (3-05-021-14)[b]	Neg.		ND		ND		ND		NA	
Oven curing--wool										
Flame attenuation (3-05-021-09)[b]	3.5	B	ND		ND		ND		ND	
Oven curing and cooling --textile (3-05-021-15)[b]	Neg.		ND		ND		ND		ND	
Rotary spin wool glass fiber manufacturing (3-05-021-04)[c]	ND		3.21	B	0.96	B	0.75	B	ND	
R-19	ND		6.21	B	0.92	B	1.23	B	ND	
R-11	ND		10.66	B	3.84	B	1.80	B	ND	
Ductboard Heavy duty	ND		0.88	B	0.53	B	0.43	B	ND	

ND = No data.
NA = Not applicable.
Neg. = Negligible.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Reference 5.
[c]Reference 4.

Table 8.11-6 (English Units)
EMISSION FACTORS FOR GLASS FIBER MANUFACTURING[a]

Source (SCC)	VOC		Phenolics		Phenol		Formaldehyde		Fluorides	
	lb/ton of Material Processed	Emission Factor Rating	lb/ton of Material Processed	Emission Factor Rating	lb/ton of Material Processed	Emission Factor Rating	lb/ton of Material Processed	Emission Factor Rating	lb/ton of Material Processed	Emission Factor Rating
Glass furnace--wool										
Electric (3-05-021-03)[b]	ND		ND		ND		ND		0.002	B
Gas--regenerative (3-05-021-01)	ND		ND		ND		ND		0.12	B
Gas--recuperative (3-05-021-02)	ND		ND		ND		ND		0.11	B
Gas--unit melter (3-05-021-07)	ND		ND		ND		ND		0.12	B
Glass furnace--textile[b]										
Gas--regenerative (3-05-021-11)	ND		ND		ND		ND		2	B
Gas--recuperative (3-05-021-12)	ND		ND		ND		ND		2	B
Gas--unit melter (3-05-021-13)	ND		ND		ND		ND		2	B
Forming--wool										
Flame attenuation (3-05-021-08)[b]	0.3		ND		ND		ND		ND	
Forming--textile (3-05-021-14)[b]	Neg.		ND		ND		ND		NA	
Oven curing--wool										
Flame attenuation (3-05-021-09)[b]	7		ND		ND		ND		ND	
Oven curing and cooling --textile (3-05-021-15)[b]	Neg.		ND		ND		ND		ND	
Rotary spin wool glass fiber manufacturing (3-05-021-04)[f]										
R-19	ND		6.92	B	1.92	B	1.50	B	ND	
R-11	ND		12.41	B	1.84	B	2.46	B	ND	
Ductboard	ND		21.31	B	7.68	B	3.61	B	ND	
Heavy duty	ND		1.74	B	1.04	B	0.85	B	ND	

ND = No data.
NA = Not applicable.
Neg. = Negligible.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Reference 5.
[c]Reference 4.

when the gas stream cools in the ductwork or in the emission control device.

Particulate matter is the principal pollutant that has been identified and measured at wool fiberglass insulation manufacturing facilities. It was known that some fraction of the PM emissions results from condensation of organic compounds used in the binder. Therefore, in evaluating emissions and control device performance for this source, a sampling method, EPA Reference Method 5E, was used that permitted collection and measurement of both solid particles and condensed PM.

Tests were performed during the production of R-11 building insulation, R-19 building insulation, ductboard, and heavy-density insulation. These products, which account for 91 percent of industry production, had densities ranging from 9.1 to 12.3 kilograms per cubic meter (kg/m^3) (0.57 to 0.77 pounds per cubic foot [lb/ft^3]) for R-11, 8.2 to 9.3 kg/m^3 (0.51 to 0.58 lb/ft^3) for R-19, and 54.5 to 65.7 kg/m^3 (3.4 to 4.1 lb/ft^3) for ductboard. The heavy-density insulation had a density of 118.5 kg/m^3 (7.4 lb/ft^3). (The remaining 9 percent of industry wool fiberglass production is a variety of specialty products for which qualitative and quantitative information is not available.) The loss on ignition (LOI) of the product is a measure of the amount of binder present. The LOI values ranged from 3.9 to 6.5 percent, 4.5 to 4.6 percent, and 14.7 to 17.3 percent for R-11, R-19, and ductboard, respectively. The LOI for heavy-density insulation is 10.6 percent. A production line may be used to manufacture more than one of these product types because the processes involved do not differ. Although the data base did not show sufficient differences in mass emission levels to establish separate emission standards for each product, the uncontrolled emission factors are sufficiently different to warrant their segregation for AP-42.

The level of emissions control found in the wool fiberglass insulation manufacturing industry ranges from uncontrolled to control of forming, curing, and cooling emissions from a line. The exhausts from these process operations may be controlled separately or in combination. Control technologies currently used by the industry include wet ESP's, low- and high-pressure-drop wet scrubbers, low- and high-temperature thermal incinerators, high-velocity air filters, and process modifications. These added control technologies are available to all firms in the industry, but the process modifications used in this industry are considered confidential. Wet ESP's are considered to be best demonstrated technology for the control of emissions from wool fiberglass insulation manufacturing lines. Therefore, it is expected that most new facilities will be controlled in this manner.

Textile Fiber Forming and Finishing - Emissions from the forming and finishing processes include glass fiber particles, resin particles, hydrocarbons (primarily phenols and aldehydes), and combustion products from dryers and ovens. Emissions are usually lower in the textile fiber glass process than in the wool fiberglass process because of lower turbulence in the forming step, roller application of coatings, and use of much less coating per ton of fiber produced.

References for Section 8.11

1. J. R. Schorr *et al.*, *Source Assessment: Pressed and Blown Glass Manufacturing Plants*, EPA-600/2-77-005, U. S. Environmental Protection Agency, Research Triangle Park, NC, January 1977.

2. *Annual Book of ASTM Standards, Part 18*, ASTM Standard C167-64 (Reapproved 1979), American Society for Testing and Materials, Philadelphia, PA.

3. *Standard of Performance For Wool Fiberglass Insulation Manufacturing Plants*, 50 FR 7700, February 25, 1985.

4. *Wool Fiberglass Insulation Manufacturing Industry: Background Information for Proposed Standards*, U. S. Environmental Protection Agency, Research Triangle Park, NC, EPA-450/3-83-022a, December 1983.

5. *Screening Study to Determine Need for Standards of Performance for New Sources in the Fiber Glass Manufacturing Industry--Draft*, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1976.

8.14 GYPSUM PROCESSING

8.14.1 Process Description[1-2]

Gypsum is calcium sulfate dihydrate ($CaSO_4 \cdot 2H_2O$), a white or gray naturally occurring mineral. Raw gypsum ore is processed into a variety of products such as a portland cement additive, soil conditioner, industrial and building plasters, and gypsum wallboard. To produce plasters or wallboard, gypsum must be partially dehydrated or calcined to produce calcium sulfate hemihydrate ($CaSO_4 \cdot \frac{1}{2}H_2O$), commonly called stucco.

A flow diagram for a typical gypsum process producing both crude and finished gypsum products is shown in Figure 8.14-1. In this process gypsum is crushed, dried, ground, and calcined. Not all of the operations shown in Figure 8.14-1 are performed at all gypsum plants. Some plants produce only wallboard, and many plants do not produce soil conditioner.

Gypsum ore, from quarries and underground mines, is crushed and stockpiled near a plant. As needed, the stockpiled ore is further crushed and screened to about 50 millimeters (2 inches) in diameter. If the moisture content of the mined ore is greater than about 0.5 weight percent, the ore must be dried in a rotary dryer or a heated roller mill. Ore dried in a rotary dryer is conveyed to a roller mill, where it is ground to the extent that 90 percent of it is less 149 micrometers (100 mesh). The ground gypsum exits the mill in a gas stream and is collected in a product cyclone. Ore is sometimes dried in the roller mill by heating the gas stream, so that drying and grinding are accomplished simultaneously and no rotary dryer is needed. The finely ground gypsum ore is known as landplaster, which may be used as a soil conditioner.

In most plants, landplaster is fed to kettle calciners or flash calciners, where it is heated to remove three-quarters of the chemically bound water to form stucco. Calcination occurs at approximately 120° to 150°C (250° to 300°F), and 0.908 megagrams (Mg) (1 ton) of gypsum calcines to about 0.77 Mg (0.85 ton) of stucco.

In kettle calciners, the gypsum is indirectly heated by hot combustion gas passed through flues in the kettle, and the stucco product is discharged into a "hot pit" located below the kettle. Kettle calciners may be operated in either batch or continuous mode. In flash calciners, the gypsum is directly contacted with hot gases, and the stucco product is collected at the bottom of the calciner.

At some gypsum plants, drying, grinding, and calcining are performed in heated impact mills. In these mills hot gas contacts gypsum as it is ground. The gas dries and calcines the ore and then conveys the stucco to a product cyclone for collection. The use of heated impact mills eliminates the need for rotary dryers, calciners, and roller mills.

Gypsum and stucco are usually transferred from one process to another by means of screw conveyors or bucket elevators. Storage bins or silos are normally located downstream of roller mills and calciners but may also be used elsewhere.

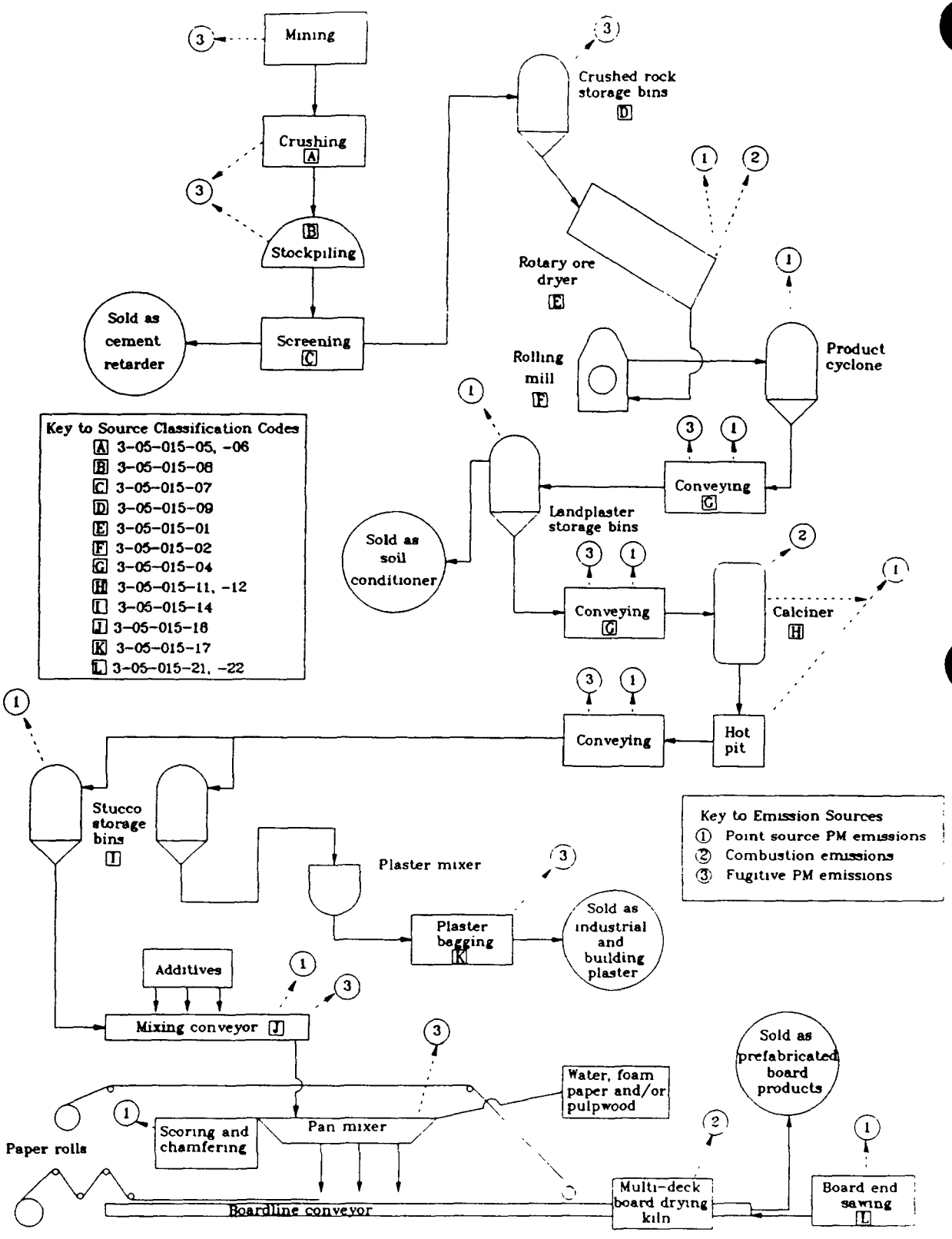


Figure 8.14-1. Overall process flow diagram for gypsum processing.[2]

In the manufacture of plasters, stucco is ground further in a tube or ball mill and then batch-mixed with retarders and stabilizers to produce plasters with specific setting rates. The thoroughly mixed plaster is fed continuously from intermediate storage bins to a bagging operation.

In the manufacture of wallboard, stucco from storage is first mixed with dry additives such as perlite, starch, fiberglass, or vermiculite. This dry mix is combined with water, soap foam, accelerators and shredded paper, or pulpwood in a pin mixer at the head of a board forming line. The slurry is then spread between two paper sheets that serve as a mold. The edges of the paper are scored, and sometimes chamfered, to allow precise folding of the paper to form the edges of the board. As the wet board travels the length of a conveying line, the calcium sulfate hemihydrate combines with the water in the slurry to form solid calcium sulfate dihydrate, or gypsum, resulting in rigid board. The board is rough-cut to length, and it enters a multideck kiln dryer, where it is dried by direct contact with hot combustion gases or by indirect steam heating. The dried board is conveyed to the board end sawing area and is trimmed and bundled for shipment.

8.14.2 Emissions and Controls[2,7]

Potential emission sources in gypsum processing plants are shown in Figure 8.14-1. While particulate matter (PM) is the dominant pollutant in gypsum processing plants, several sources may emit gaseous pollutants also. The major sources of PM emissions include rotary ore dryers, grinding mills, calciners, and board end sawing operations. Particulate matter emission factors for these operations are shown in Table 8.14-1. In addition, emission factors for PM less than or equal to 10 microns in aerodynamic diameter (PM_{10}) emissions from selected processes are presented in Table 8.14-1. All of these factors are based on output production rates. Particle size data for ore dryers, calciners, and board end sawing operations are shown in Tables 8.14-2 and 8.14-3.

The uncontrolled emission factors presented in Table 8.14-1 represent the process dust entering the emission control device. It is important to note that emission control devices are frequently needed to collect the product from some gypsum processes and, thus, are commonly thought of by the industry as process equipment and not as added control devices.

Emissions sources in gypsum plants are most often controlled with fabric filters. These sources include:

- rotary ore dryers (SCC 3-05-015-01)
- roller mills (SCC 3-05-015-02)
- impact mills (SCC 3-05-015-13)
- kettle calciners (SCC 3-05-015-11)
- flash calciners (SCC 3-05-015-12)
- board end sawing (SCC 3-05-015-21,-22)
- scoring and chamfering (SCC 3-05-015-__)
- plaster mixing and bagging (SCC 3-05-015-16,-17)
- conveying systems (SCC 3-05-015-04)
- storage bins (SCC 3-05-015-09,-10,-14)

Uncontrolled emissions from scoring and chamfering, plaster mixing and bagging, conveying systems, and storage bins are not well quantified.

Emissions from some gypsum sources are also controlled with electrostatic precipitators (ESP's). These sources include rotary ore dryers, roller mills, kettle calciners, and conveying systems. Although rotary ore dryers may be controlled separately, emissions from roller mills and conveying systems are usually controlled jointly with kettle calciner emissions. Moisture in the kettle calciner exit gas improves the ESP performance by lowering the resistivity of the dust.

TABLE 8.14-1 (METRIC UNITS)
EMISSION FACTORS FOR GYPSUM PROCESSING[a]
All Emission Factors in kg/Mg of Output Rate
Ratings (A-E) follow Each Emission Factor

Process (SCC)	Filterable PM[b]		PM_{10}		CO_2[c]	
Crushers, screens, stockpiles, and roads (3-05-015-05,-06,-07,-08)	[d]		[d]		NA	
Rotary ore dryers (3-05-015-01)	$0.0042(FFF)^{1.7}$[e]	D	$0.00034(FFF)^{1.7}$	D	12[f]	D
Rotary ore dryers w/ fabric filters (3-05-015-01)	0.020[g]	D	0.0052	D	NA	
Roller mills w/ cyclones (3-05-015-02)	1.3[h]	D	ND		NA	
Roller mills w/ fabric filters (3-05-015-02)	0.060[h]	D	ND		NA	
Roller mill and kettle calciner w/electrostatic precipitators (3-05-015-02,-11)	0.050[h,i]	D	ND		ND	
Continuous kettle calciners and hot pit (3-05-015-11)	21[j]	D	13	D	ND	
Continuous kettle calciners and hot pit w/ fabric filters (3-05-015-11)	0.0030[j]	D	ND		NA	
Continuous kettle calciners w/ cyclones and electrostatic precipitators (3-05-015-11)	0.050[j]	D	ND		NA	
Flash calciners (3-05-015-12)	19[k]	D	7.2	D	55[l]	D
Flash calciners w/fabric filters (3-05-015-12)	0.020[k]	D	0.017	D	ND	
Impact mills w/cyclones (3-05-015-13)	50[m]	D	ND		NA	
Impact mills w/ fabric filters (3-05-015-13)	0.010[m]	D	ND		NA	
Board end sawing--2.4-m boards (3-05-015-21)	0.040[n]	D	ND		NA	
Board end sawing--3.7-m boards (3-05-015-22)	0.030[n]	D	ND	D	NA	
Board end sawing w/ fabric filters--2.4- and 3.7-m boards (3-05-015-21,-22)	36[o]	D	27		NA	

Table 8.14-1 (METRIC UNITS) (continued)

ND = No data available. NA = Not applicable.

[a]Factors represent uncontrolled emissions unless otherwise specified.

[b]Filterable PM is that PM collected on or prior to an EPA Method 5 (or equivalent) sampling train.

[c]Typical pollution control devices generally have a negligible effect on CO_2 emissions.

[d]Factors for these operations are in Sections 8.19 and 11.2.

[e]References 3-4, 8, 11-12. Equation is for the emission rate upstream of any process cyclones and applies only to concurrent rotary ore dryers with flowrates of 7.5 cubic meters per second (m^3/s) or less. FFF in the uncontrolled emission factor equation is "flow feed factor," the ratio of gas mass rate per unit dryer cross section area to the dry mass feed rate, in the following units: (kg/hr-m^2 of gas flow)/(Mg/hr dry feed). Measured uncontrolled emission factors for 4.2 and 5.7 m^3/s range from 5 to 60 kg/Mg.

[f]References 3-4.

[g]References 3-4, 8, 11-12. Applies to rotary dryers with and without cyclones upstream of fabric filter.

[h]References 11-14. Applies to both heated and unheated roller mills.

[i]References 11-14. Factor is for combined emissions from roller mills and kettle calciners, based on the sum of the roller mill and kettle calciner output rates.

[j]References 4-5, 11, 13-14. Emission factors based on the kettle and the hot pit do not apply to batch kettle calciners.

[k]References 3, 6, 10.

[l]References 3, 6, 9.

[m]References 9, 15. As used here, an impact mill is a process unit used to dry, grind, and calcine gypsum simultaneously.

[n]References 4-5, 16. Emission factor units = kg/m^2. Based on 13 mm board thickness and 1.2 m board width. For other thicknesses, multiply the appropriate emission factor by 0.079 times board thickness in mm.

[o]References 4-5, 16. Emission factor units = $kg/10^6\ m^2$.

TABLE 8.14-1 (ENGLISH UNITS)
EMISSION FACTORS FOR GYPSUM PROCESSING[a]
All Emission Factors in Rate
Ratings (A-E) follow Each Emission Factor

Process (SCC)	Filterable PM[b]		PM_{10}		CO_2[c]	
Crushers, screens, stockpiles, and roads (3-05-015-05,-06,-07,-08)	[d]		[d]		NA	
Rotary ore dryers (3-05-015-01)	$0.16(FFF)^{1.77}$[e]	D	$0.013(FFF)^{1.7}$	D	23[f]	D
Rotary ore dryers w/fabric filters (3-05-015-01)	0.040[g]	D	0.010	D	NA	
Roller mills w/cyclones (3-05-015-02)	2.6[h]	D	ND		NA	
Roller mills w/ fabric filters (3-05-015-02)	0.12[h]	D	ND		NA	
Roller mill and kettle calciner w/ electrostatic precipitators (3-05-015-02,-11)	0.090[h,i]	D	ND		ND	
Continuous kettle calciners and hot pit (3-05-015-11)	41[j]	D	26	D	ND	
Continuous kettle calciners and hot pit w/ fabric filters (3-05-015-11)	0.0060[j]	D	ND		NA	
Continuous kettle calciners w/ cyclones and electrostatic precipitators (3-05-015-11)	0.090[j]	D	ND		NA	
Flash calciners (3-05-015-12)	37[k]	D	14	D	110[l]	D
Flash calciners w/fabric filters (3-05-015-12)	0.040[k]	D	0.034	D	ND	
Impact mills w/ cyclones (3-05-015-13)	100[m]	D	ND		NA	
Impact mills w/ fabric filters (3-05-015-13)	0.020[m]	D	ND		NA	
Board end sawing--8-ft boards (3-05-015-21)	0.80[n]	D	ND		NA	
Board end sawing--12-ft boards (3-05-015-22)	0.50[n]	D	ND		NA	
Board end sawing w/ fabric filters--8- and 12-ft boards (3-05-015-21,-22)	7.5[o]	D	5.7	D	NA	

Table 8.14-1 (ENGLISH UNITS) (continued)

ND = No data available. NA = Not applicable.

[a]Factors represent uncontrolled emissions unless otherwise specified.

[b]Filterable PM is that particulate collected on or prior to an EPA Method 5 (or equivalent) sampling train.

[c]Typical pollution control devices generally have a negligible effect on CO_2 emissions.

[d]Factors for these operations are in Sections 8.19 and 11.2.

[e]References 3-4, 8, 11-12. Equation is for the emission rate upstream of any process cyclones and applies only to concurrent rotary ore dryers with flowrates of 16,000 actual cubic feet per minute (acfm) or less. FFF in the uncontrolled emission factor equation is "flow feed factor," the ratio of gas mass rate per unit dryer cross section area to the dry mass feed rate, in the following units: (lb/hr-ft^2 of gas flow)/(ton/hr dry feed). Measured uncontrolled emission factors for 9,000 and 12,000 acfm range from 10 to 120 lb/ton.

[f]References 3-4.

[g]References 304, 8, 11-12. Applies to rotary dryers with and without cyclones upstream of fabric filter.

[h]References 11-14. Applies to both heated and unheated roller mills.

[i]References 11-14. Factor is for combined emissions from roller mills and kettle calciners, based on the sum of the roller mill and kettle calciner output rates.

[j]References 4-05, 11, 13-14. Emission factors based on the kettle and the hot pit do not apply to batch kettle calciners.

[k]References 3, 6, 10.

[l]References 3, 6, 9.

[m]References 9, 15. As used here, an impact mill is a process unit used to dry, grind, and calcine gypsum simultaneously.

[n]References 4-5, 16. Emission factor units = lb/100 ft^2. Based on 1/2-in. board thickness and 4-ft board width. For other thicknesses, multiply the appropriate emission factor by 2 times board thickness in inches.

[o]References 4-5, 16. Emission factor units = lb/10^6 ft^2.

TABLE 8.14-2. SUMMARY OF PARTICLE SIZE DISTRIBUTION DATA FOR UNCONTROLLED PM EMISSIONS FROM GYPSUM PROCESSING[a]
EMISSION FACTOR RATING: D

Diameter (microns)	Cumulative % less than diameter			
	Rotary ore dryer[b]	Rotary ore dryer with cyclone[c]	Continuous kettle calciner[d]	Flash calciner[e]
2.0	1	12	17	10
10.0	8	45	63	38

[a]Weight percent given as filterable PM. Diameter is given as aerodynamic diameter, except for continuous kettle calciner, which is given as equivalent diameter, as determined by Bahco and Sedigraph analyses.
[b]Reference 3.
[c]Reference 4.
[d]References 4, 5.
[e]References 3, 6.

TABLE 8.14-3. SUMMARY OF PARTICLE SIZE DISTRIBUTION DATA FOR FABRIC FILTER-CONTROLLED PM EMISSIONS FROM GYPSUM MANUFACTURING[a]
EMISSION FACTOR RATING: D

Diameter (microns)	Cumulative % less than diameter		
	Rotary ore dryer[b]	Flash calciner[c]	Board end sawing[c]
2.0	9	52	49
10.0	26	84	76

[a]Aerodynamic diameters, Andersen analysis.
[b]Reference 3.
[c]Reference 3, 6.

Other sources of PM emissions in gypsum plants are primary and secondary crushers, screens, stockpiles, and roads. If quarrying is part of the mining operation, PM emissions may also result from drilling and blasting. Emission factors for some of these sources are presented in Sections 8.19 and 11.2. Gaseous emissions from gypsum processes result from fuel combustion and may include nitrogen oxides, sulfur oxides, carbon monoxide, and carbon dioxide (CO_2). Processes using fuel include rotary ore dryers, heated roller mills, impact mills, calciners, and board drying kilns. Although some plants use residual fuel oil, the majority of the industry uses clean fuels such as natural gas or distillate fuel oil. Emissions from fuel combustion may be estimated using emission factors presented in Sections 1.3 and 1.4 and fuel consumption data in addition to those emission factors presented in Table 8.14-1.

REFERENCES FOR SECTION 8.14

1. *Kirk-Othmer Encyclopedia of Chemical Technology*, Volume 4, John Wiley & Sons, Inc., New York, 1978.

2. *Gypsum Industry - Background Information for Proposed Standards (Draft)*, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1981.

3. *Source Emissions Test Report, Gold Bond Building Products*, EMB-80- GYP-1, U. S. Environmental Protection Agency, Research Triangle Park, NC, November 1980.

4. *Source Emissions Test Report, United States Gypsum Company*, EMB-80- GYP-2, U. S. Environmental Protection Agency, Research Triangle Park, NC, November 1980.

5. *Source Emission Tests, United States Gypsum Company Wallboard Plant*, EMB-80-GYP-6, U. S. Environmental Protection Agency, Research Triangle Park, NC, January 1981.

6. *Source Emission Tests, Gold Bond Building Products*, EMB-80-GYP-5, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1980.

7. S. Oglesby and G. B. Nichols, *A Manual of Electrostatic Precipitation Technology, Part II: Application Areas*, APTD-0611, U. S. Environmental Protection Agency, Cincinnati, OH, August 25, 1970.

8. *Official Air Pollution Emission Tests Conducted on the Rock Dryer and No. 3 Calcidyne Unit, Gold Bond Building Products*, Report No. 5767, Rosnagel and Associates, Medford, NJ, August 3, 1979.

9. *Particulate Analysis of Calcinator Exhaust at Western Gypsum Company*, Kramer, Callahan and Associates, Rosario, NM, April 1979. Unpublished.

10. *Official Air Pollution Tests Conducted on the #1 Calcidyner Baghouse Exhaust at the National Gypsum Company*, Report No. 2966, Rossnagel and Associates, Atlanta, GA, April 10, 1978.

11. *Report to United States Gypsum Company on Particulate Emission Compliance Testing*, Environmental Instrument Systems, Inc., South Bend, IN, November 1975. Unpublished.

12. *Particulate Emission Sampling and Analysis, United States Gypsum Company*, Environmental Instrument Systems, Inc., South Bend, IN, July 1973. Unpublished.

13. Written communication from Wyoming Air Quality Division, Cheyenne, WY, to M. Palazzolo, Radian Corporation, Durham, NC, 1980.

14. Written communication from V. J. Tretter, Georgia-Pacific Corporation, Atlanta, GA, to M. E. Kelly, Radian Corporation, Durham, NC, November 14, 1979.

15. Telephone communication between M. Palazzolo, Radian Corporation, Durham, NC, and D. Louis, C. E. Raymond Company, Chicago, IL, April 23, 1981.

16. Written communication from M. Palazzolo, Radian Corporation, Durham, NC, to B. L. Jackson, Weston Consultants, West Chester, PA, June 19, 1980.

17. Telephone communication between P. J. Murin, Radian Corporation, Durham, NC, and J. W. Pressler, U. S. Department of the Interior, Bureau of Mines, Washington, DC, November 6, 1979.

8.16 MINERAL WOOL MANUFACTURING

8.16.1 General[1,2]

Mineral wool often is defined as any fibrous glassy substance made from minerals (typically natural rock materials such as basalt or diabase) or mineral products such as slag and glass. Because glass wool production is covered separately in AP-42 (Section 8.11), this section deals only with the production of mineral wool from natural rock and slags such as iron blast furnace slag, the primary material, and copper, lead, and phosphate slags. These materials are processed into insulation and other fibrous building materials that are used for structural strength and fire resistance. Generally, these products take one of four forms: "blowing" wool or "pouring" wool, which is put into the structural spaces of buildings; batts, which may be covered with a vapor barrier of paper or foil and are shaped to fit between the structural members of buildings; industrial and commercial products such as high-density fiber felts and blankets, which are used for insulating boilers, ovens, pipes, refrigerators, and other process equipment; and bulk fiber, which is used as a raw material in manufacturing other products, such as ceiling tile, wall board, spray-on insulation, cement, and mortar.

Mineral wool manufacturing facilities are included in Standard Industrial Classification (SIC) Code 3296, mineral wool. This SIC code also includes the production of glass wool insulation products, but those facilities engaged in manufacturing textile glass fibers are included in SIC Code 3229. The six digit source category code (SCC) for mineral wool manufacturing is 3-05-017.

8.16.2 Process Description[1,4,5]

Most mineral wool produced in the United States today is produced from slag or a mixture of slag and rock. Most of the slag used by the industry is generated by integrated iron and steel plants as a blast furnace byproduct from pig iron production. Other sources of slag include the copper, lead, and phosphate industries. The production process has three primary components--molten mineral generation in the cupola, fiber formation and collection, and final product formation. Figure 8.16-1 illustrates the mineral wool manufacturing process.

The first step in the process involves melting the mineral feed. The raw material (slag and rock) is loaded into a cupola in alternating layers with coke at weight ratios of about 5 to 6 parts mineral to 1 part coke. As the coke is ignited and burned, the mineral charge is heated to the molten state at a temperature of 1300° to 1650°C (2400° to 3000°F). Combustion air is supplied through tuyeres located near the bottom of the furnace. Process modifications at some plants include air enrichment and the use of natural gas auxiliary burners to reduce coke consumption. One facility also reported using an aluminum flux byproduct to reduce coke consumption.

The molten mineral charge exits the bottom of the cupola in a water-cooled trough and falls onto a fiberization device. Most of the mineral wool produced in the United States is made by variations of two fiberization methods. The Powell process uses groups of rotors revolving at a high rate of speed to form the fibers. Molten material is distributed in a thin film on the surfaces of the rotors and then is thrown off by centrifugal force. As the material is discharged from the rotor, small globules develop on the rotors and form long, fibrous tails as they travel horizontally. Air or steam

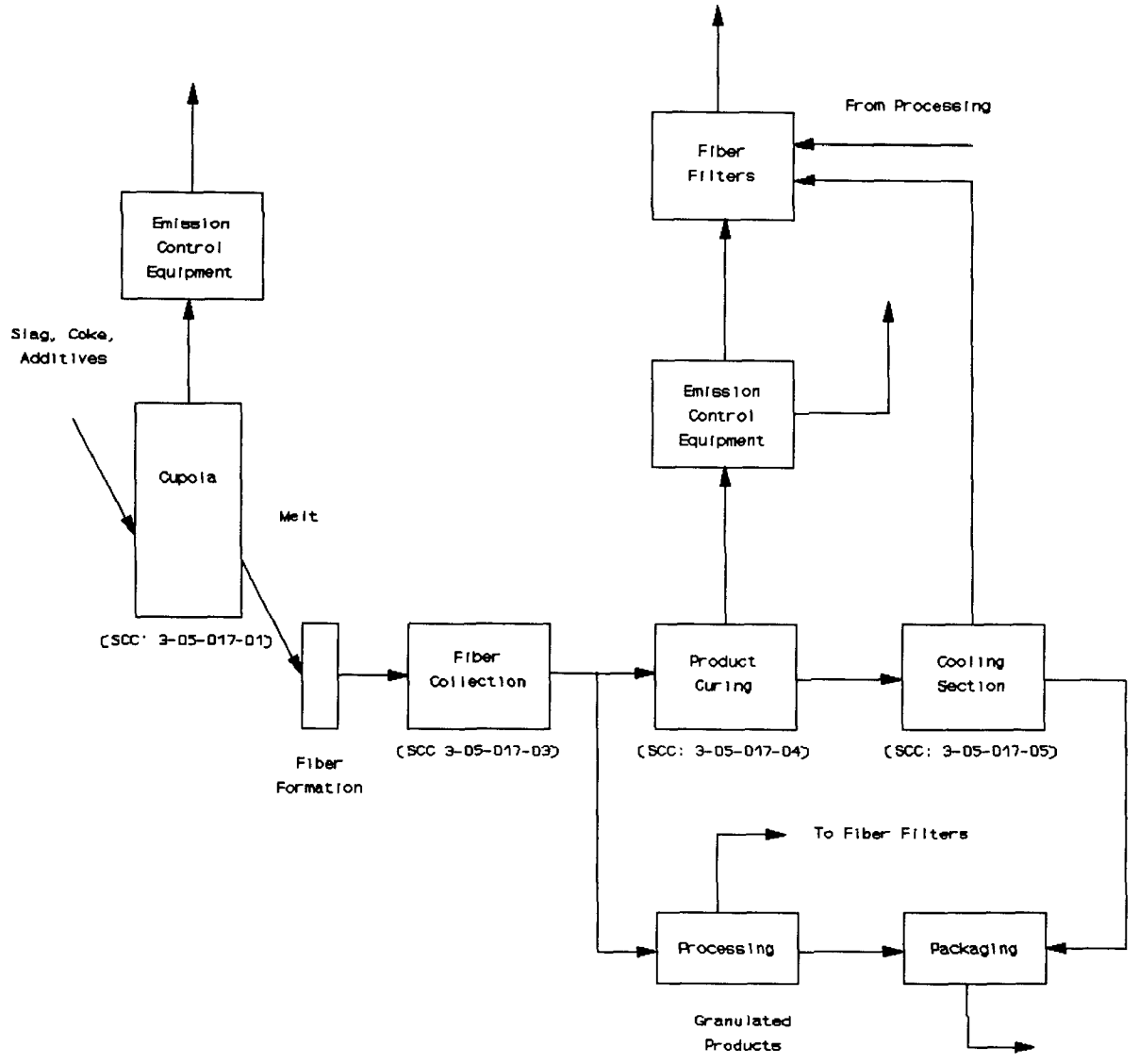


Figure 8.16-1. Mineral wool manufacturing process flow diagram.

may be blown around the rotors to assist in fiberizing the material. A second fiberization method, the Downey process, uses a spinning concave rotor with air or steam attenuation. Molten material is distributed over the surface of the rotor, from which it flows up and over the edge and is captured and directed by a high-velocity stream of air or steam.

During the spinning process, not all globules that develop are converted into fiber. The nonfiberized globules that remain are referred to as "shot." In raw mineral wool, as much as half of the mass of the product may consist of shot. As shown in Figure 8.16-1, shot is usually separated from the wool by gravity immediately following fiberization.

Depending on the desired product, various chemical agents may be applied to the newly formed fiber immediately following the rotor. In almost all cases, an oil is applied to suppress dust and, to some degree, anneal the fiber. This oil can be either a proprietary product or a medium-weight fuel or lubricating oil. If the fiber is intended for use as loose wool or bulk products, no further chemical treatment is necessary. If the mineral wool product is required to have structural rigidity, as in batts and industrial felt, a binding agent is applied with or in place of the oil treatment. This binder is typically a phenol-formaldehyde resin that requires curing at elevated temperatures. Both the oil and the binder are applied by atomizing the liquids and spraying the agents to coat the airborne fiber.

After formation and chemical treatment, the fiber is collected in a blowchamber. Resin-and/or oil-coated fibers are drawn down on a wire mesh conveyor by fans located beneath the collector. The speed of the conveyor is set so that a wool blanket of desired thickness can be obtained.

Mineral wool containing the binding agent is carried by conveyor to a curing oven, where the wool blanket is compressed to the appropriate density and the binder is baked. Hot air, at a temperature of 150° to 320°C (300° to 600°F), is forced through the blanket until the binder has set. Curing time and temperature depend on the type of binder used and the mass rate through the oven. A cooling section follows the oven, where blowers force air at ambient temperatures through the wool blanket.

To make batts and industrial felt products, the cooled wool blanket is cut longitudinally and transversely to the desired size. Some insulation products are then covered with a vapor barrier of aluminum foil or asphalt-coated kraft paper on one side and untreated paper on the other side. The cutters, vapor barrier applicators, and conveyors are sometimes referred to collectively as a batt machine. Those products that do not require a vapor barrier, such as industrial felt and some residential insulation batts, can be packed for shipment immediately after cutting.

Loose wool products consist primarily of blowing wool and bulk fiber. For these products, no binding agent is applied, and the curing oven is eliminated. For granulated wool products, the fiber blanket leaving the blowchamber is fed to a shredder and pelletizer. The pelletizer forms small, 1-inch diameter pellets and separates shot from the wool. A bagging operation completes the processes. For other loose wool products, fiber can be transported directly from the blowchamber to a baler or bagger for packaging.

8.16.3 Emissions and Controls[1,13]

The sources of emissions in the mineral wool manufacturing industry are the cupola; binder storage, mixing, and application; the blow chamber; the curing oven; the mineral wool cooler; materials handling and bagging operations; and wastewater treatment and storage. With the exception of lead, the industry emits the full range of criteria pollutants. Also, depending on the particular types of slag and binding agents used, the facilities may emit both metallic and organic hazardous air pollutants (HAP's).

The primary source of emissions in the mineral wool manufacturing process is the cupola. It is a significant source of particulate matter (PM) emissions and is likely to be a source of PM less than 10 micrometers (μm) in diameter (PM-10) emissions, although no particle size data are available. The cupola is also a potential source of HAP metal emissions attributable to the coke and slags used in the furnace. Coke combustion in the furnace produces carbon monoxide (CO), carbon dioxide (CO_2), and nitrogen oxide (NO_x) emissions. Finally, because blast furnace slags contain sulfur, the cupola is also a source of sulfur dioxide (SO_2) and hydrogen sulfide (H_2S) emissions.

The blowchamber is a source of PM (and probably PM-10) emissions. Also, the annealing oils and binders used in the process can lead to VOC emissions from the process. Other sources of VOC emissions include batt application, the curing oven, and wastewater storage and treatment. Finally, fugitive PM emissions can be generated during cooling, handling, and bagging operations. Tables 8.16-1 and 8.16-2 present emission factors for filterable PM emissions from various mineral wool manufacturing processes; Tables 8-16.3 and 8.16-4 show emission factors for CO, CO_2, SO_2, and sulfates; and Tables 8.16-5 and 8.16-6 present emission factors for NO_x, N_2O, H_2S and fluorides.

Mineral wool manufacturers use a variety of air pollution control techniques, but most are directed toward PM control with minimal control of other pollutants. The industry has given greatest attention to cupola PM control, with two-thirds of the cupolas in operation having fabric filter control systems. Some cupola exhausts are controlled by wet scrubbers and electrostatic precipitators (ESP's); cyclones are also used for cupola PM control either alone or in combination with other control devices. About half of the blow chambers in the industry also have some level of PM control, with the predominant control device being low-energy wet scrubbers. Cyclones and fabric filters have been used to a limited degree on blow chambers. Finally, afterburners have been used to control VOC emissions from blow chambers and curing ovens and CO emissions from cupolas.

Table 8.16-1. (Metric Units)
EMISSION FACTORS FOR MINERAL WOOL MANUFACTURING[a]

Process (SCC)	Filterable PM[b]	
	kg/Mg of product	Emission Factor Rating
Cupola[c] (30501701)	8.2	E
Cupola with fabric filter[d] (30501701)	0.051	D
Reverberatory furnace[e] (30501702)	2.4	E
Batt curing oven[e] (30501704)	1.8	E
Batt curing oven with ESP[f] (30501704)	0.36	D
Blow chamber[c] (30501703)	6.0	E
Blow chamber with wire mesh filter[g] (30501703)	0.45	D
Cooler[e] (30501705)	1.2	E

[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
[c]References 1, 12. Activity level is assumed to be total feed charged.
[d]References 6, 7, 8, 10, and 11. Activity level is total feed charged.
[e]Reference 12.
[f]Reference 9.
[g]Reference 7. Activity level is mass of molten mineral feed charged.

Table 8.16-2. (English Units)
EMISSION FACTORS FOR MINERAL WOOL MANUFACTURING[a]

Process (SCC)	Filterable PM[b]	
	lb/ton of product	Emission Factor Rating
Cupola[c] (30501701)	16	E
Cupola with fabric filter[d] (30501701)	0.10	D
Reverberatory furnace[e] (30501702)	4.8	E
Batt curing oven[e] (30501704)	3.6	E
Batt curing oven with ESP[f] (30501704)	0.72	D
Blow chamber[c] (30501703)	12	E
Blow chamber with wire mesh filter[g] (30501703)	0.91	D
Cooler[e] (30501705)	2.4	E

[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
[c]Reference 1, 12. Activity level is assumed to be total feed charged.
[d]References 6, 7, 8, 10, and 11. Activity level is total feed charged.
[e]Reference 12.
[f]Reference 9.
[g]Reference 7. Activity level is mass of molten mineral feed charged.

Table 8.16-3 (Metric Units)
EMISSION FACTORS FOR MINERAL WOOL MANUFACTURING[a]

Source (SCC)	CO[b]		CO_2[b]		SO_2		SO_3	
	kg/Mg of total feed charged	Emission Factor Rating	kg/Mg of total feed charged	Emission Factor Rating	kg/Mg of total feed charged	Emission Factor Rating	kg/Mg of total feed charged	Emission Factor Rating
Cupola (30501701)	125	D	260	D	4.0[c]	D	3.2[d]	E
Cupola with fabric filter (30501701)	NA		NA		NA		0.077[b]	E
Batt curing oven (30501704)	ND		ND		0.58[d]	E	ND	
Blow chamber (30501703)	ND		80[e]	E	0.43[d]	E	ND	
Cooler (30501705)	ND		ND		0.034[d]	E	ND	

NA = Not applicable.
ND = No data available.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Reference 6.
[c]References 6, 10, and 11.
[d]Reference 12.
[e]Reference 9.

Table 8.16-4 (English Units)
EMISSION FACTORS FOR MINERAL WOOL MANUFACTURING[a]

Source (SCC)	CO[b]		CO_2[b]		SO_2		SO_3	
	lb/ton of total feed charged	Emission Factor Rating	lb/ton of total feed charged	Emission Factor Rating	lb/ton of total feed charged	Emission Factor Rating	lb/ton of total feed charged	Emission Factor Rating
Cupola (30501701)	250	D	520	D	8.0[a]	D	6.3[d]	E
Cupola with fabric filter (30501701)	NA		NA		NA		0.15[b]	E
Batt curing oven (30501704)	ND		ND		1.2[d]	E	ND	
Blow chamber (30501703)	ND		160[e]	E	0.087[d]	E	ND	
Cooler (30501705)	ND		ND		0.068[d]	E	ND	

NA = Not applicable.
ND = No data available.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Reference 6.
[c]References 6, 10, and 11.
[d]Reference 12.
[e]Reference 9.

Table 8.16-5 (Metric Units)
EMISSION FACTORS FOR MINERAL WOOL MANUFACTURING[a]

Process (SCC)	NO_x		N_2O		H_2S		Fluorides	
	kg/Mg of total feed charged	Emission Factor Rating	kg/Mg of total feed charged	Emission Factor Rating	kg/Mg of total feed charged	Emission Factor Rating	kg/Mg of total feed charged	Emission Factor Rating
Cupola (30501701)	0.8[b]	E	ND		1.5[b]	E	ND	
Cupola with fabric filter (30501701)	ND		ND		ND		0.019[c]	D
Cupola with fabric filter (30501701)	ND		ND		ND		0.19[d]	D
Batt curing oven (30501714)	ND		0.079	E	ND		ND	

ND = No data available.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Reference 1.
[c]References 10 and 11. Coke only used as fuel.
[d]References 10 and 11. Fuel combination of coke and aluminum smelting byproducts.

Table 8.16-6 (English Units)
EMISSION FACTORS FOR MINERAL WOOL MANUFACTURING[a]

Process (SCC)	NO_x		N_2O		H_2S		Fluorides	
	lb/ton of total feed charged	Emission Factor Rating	lb/ton of total feed charged	Emission Factor Rating	lb/ton of total feed charged	Emission Factor Rating	lb/ton of total feed charged	Emission Factor Rating
Cupola (30501701)	1.6[b]	E	ND		3.0b	E	ND	
Cupola with fabric filter (30501701)	ND		ND		ND		0.038[c]	D
Cupola with fabric filter (30501701)	ND		ND		ND		0.38[d]	D
Batt curing oven (30501714)	ND		0.16	E	ND		ND	

ND = No data available.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Reference 1.
[c]References 10 and 11. Coke only used as fuel.
[d]References 10 and 11. Fuel combination of coke and aluminum smelting byproducts.

REFERENCES FOR SECTION 8.16

1. *Source Category Survey: Mineral Wool Manufacturing Industry*, EPA-450/3-80-016, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1980.

2. *The Facts on Rocks and Slag Wool*, Pub. No. N 020, North American Insulation Manufacturers Association, Alexandria, VA, Undated.

3. ICF Corporation, *Supply Response to Residential Insulation Retrofit Demand*, Report to the Federal Energy Administration, Contract No. P-14-77-5438-0, Washington, D.C., June 1977.

4. Personal communication between F. May, U.S.G. Corporation, Chicago, Illinois, and R. Marinshaw, Midwest Research Institute, Cary, NC, June 5, 1992.

5. Memorandum from K. Schuster, N.C. Department of Environmental Management, to M. Aldridge, American Rockwool, April 25, 1988.

6. *Sulfur Oxide Emission Tests Conducted on the #1 and #2 Cupola Stacks in Leeds, Alabama for Rock Wool Company, November 8 & 9, 1988*, Guardian Systems, Inc., Leeds, AL, Undated.

7. *Particulate Emissions Tests for U.S. Gypsum Company on the Number 4 Dry Filter and Cupola Stack Located in Birmingham, Alabama on January 14, 1981*, Guardian Systems, Inc., Birmingham, AL, Undated.

8. Untitled Test Report, Cupolas Nos. 1, 2, and 3, U.S. Gypsum, Birmingham, AL, June 1979.

9. *Particulate Emission Tests on Batt Curing Oven for U.S. Gypsum, Birmingham, Alabama on October 31-November 1, 1977*, Guardian Systems, Inc., Birmingham, AL, Undated.

10. J.V. Apicella, *Particulate, Sulfur Dioxide, and Fluoride Emissions from Mineral Wool Emission, with Varying Charge Compositions, American Rockwool, Inc. Spring Hope, N.C. 27882*, Alumina Company of America, Alcoa Center, PA, June 1988.

11. J.V. Apicella, *Compliance Report on Particulate, Sulfur Dioxide, Fluoride, and Visual Emissions from Mineral Wool Production, American Rockwool, Inc., Spring Hope, NC 27882*, Aluminum Company of America, Alcoa Center, PA, February 1988.

12. J.L. Spinks, "Mineral Wool Furnaces," In: *Air Pollution Engineering Manual*, J.A. Danielson, ed., U. S. DHEW, PHS, National Center for Air Pollution Control, Cincinnati, OH. PHS Publication Number 999-AP-40, 1967, pp. 343-347.

13. Personal communication between M. Johnson, U. S. Environmental Protection Agency, Research Triangle Park, NC, and D. Bullock, Midwest Research Institute, Cary, NC, March 22, 1993.

8.17 PERLITE PROCESSING

8.17.1 Process Description[1,2]

Perlite is a glassy volcanic rock with a pearl-like luster. It usually exhibits numerous concentric cracks that cause it to resemble an onion skin. A typical perlite sample is composed of 71 to 75 percent silicon dioxide, 12.5 to 18.0 percent alumina, 4 to 5 percent potassium oxide, 1 to 4 percent sodium and calcium oxides, and trace amounts of metal oxides.

Crude perlite ore is mined, crushed, dried in a rotary dryer, ground, screened, and shipped to expansion plants. Horizontal rotary or vertical stationary expansion furnaces are used to expand the processed perlite ore.

The normal size of crude perlite expanded for use in plaster aggregates ranges from plus 250 micrometers (μm) (60 mesh) to minus 1.4 millimeters (mm) (12 mesh). Crude perlite expanded for use as a concrete aggregate ranges from 1 mm (plus 16 mesh) to 0.2 mm (plus 100 mesh). Ninety percent of the crude perlite ore expanded for horticultural uses is greater than 841 μm (20 mesh).

Crude perlite is mined using open-pit methods and then is moved to the plant site, where it is stockpiled. Figure 8.17-1 is a flow diagram of crude ore processing. The first processing step is to reduce the diameter of the ore to approximately 1.6 centimeters (cm) (0.6 inch [in.]) in a primary jaw crusher. The crude ore is then passed through a rotary dryer, which reduces the moisture content from between 4 and 10 percent to less than 1 percent.

After drying, secondary grinding takes place in a closed-circuit system using screens, air classifiers, hammer mills, and rod mills. Oversized material produced from the secondary circuit is returned to the primary crusher. Large quantities of fines, produced throughout the processing stages, are removed by air classification at designated stages. The desired size processed perlite ore is stored until it is shipped to an expansion plant.

At the expansion plants, the processed ore is either preheated or fed directly to the furnace. Preheating the material to approximately 430°C (800°F) reduces the amount of fines produced in the expansion process, which increases usable output and controls the uniformity of product density. In the furnace, the perlite ore reaches a temperature of 760° to 980°C (1400° to 1800°F), at which point it begins to soften to a plastic state where the entrapped combined water is released as steam. This causes the hot perlite particles to expand 4 to 20 times their original size. A suction fan draws the expanded particles out of the furnace and transports them pneumatically to a cyclone classifier system to be collected. The air-suspended perlite particles are also cooled as they are transported to the collection equipment. The cyclone classifier system collects the expanded perlite, removes the excessive fines, and discharges gases to a baghouse or wet scrubber for air pollution control.

The grades of expanded perlite produced can also be adjusted by changing the heating cycle, altering the cutoff points for size collection, and blending various crude ore sizes. All processed products are graded for specific uses and are usually stored before being shipped. Most production rates are less than 1.8 megagrams per hour (Mg/hr) megagrams (2 tons/hr), and expansion furnace

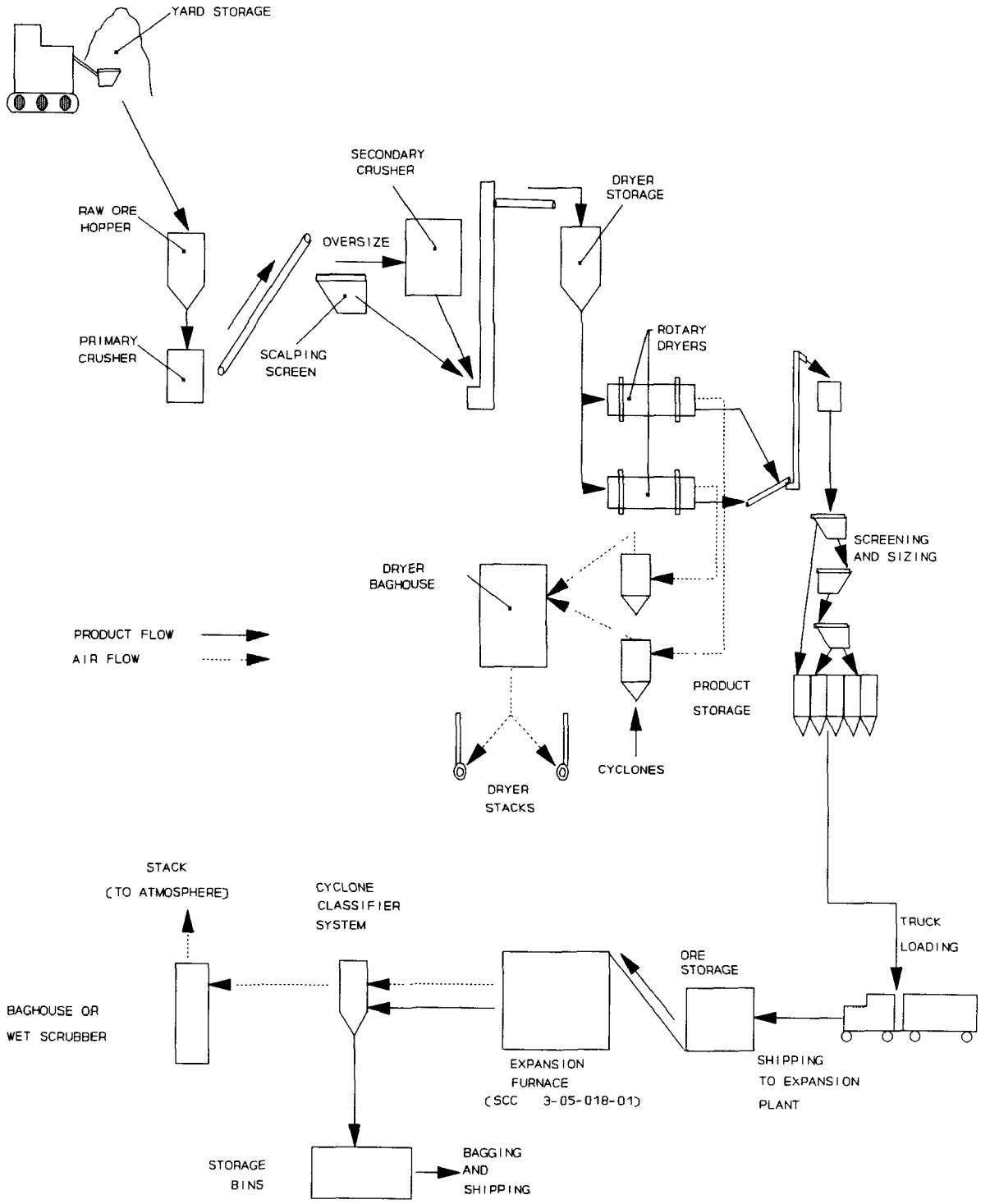


Figure 8.17-1. Flow diagram for perlite processing.[1]

temperatures range from 870° to 980°C (1600° to 1800°F). Natural gas is typically used for fuel, although No. 2 fuel oil and propane are occasionally used. Fuel consumption varies from 2,800 to 8,960 kilojoules per kilogram (kJ/kg) (2.4×10^6 to 7.7×10^6 British thermal units per ton [Btu/ton]) of product.

8.17.2 Emissions and Controls[1,3-11]

The major pollutant of concern emitted from perlite processing facilities is particulate matter (PM). The dryers, expansion furnaces, and handling operations can all be sources of PM emissions. Emissions of nitrogen oxides from perlite expansion and drying generally are negligible. When sulfur-containing fuels are used, sulfur dioxide (SO_2) emissions may result from combustion sources. However, the most common type of fuel used in perlite expansion furnaces and dryers is natural gas, which is not a significant source of SO_2 emissions.

Test data from one perlite plant indicate that perlite expansion furnaces emit a number of trace elements, including aluminum, calcium, chromium, fluorine, iron, lead, magnesium, manganese, mercury, nickel, titanium, and zinc. However, because the data consist of a single test run, emission factors were not developed for these elements. The sample also was analyzed for beryllium, uranium, and vanadium, but these elements were not detected.

To control PM emissions from both dryers and expansion furnaces, the majority of perlite plants use baghouses, some use cyclones either alone or in conjunction with baghouses, and a few use scrubbers. Frequently, PM emissions from material handling processes and from the dryers are controlled by the same device. Large plants generally have separate fabric filters for dryer emissions, whereas small plants often use a common fabric filter to control emissions from dryers and materials handling operations. In most plants, fabric filters are preceded by cyclones for product recovery. Wet scrubbers are also used in a small number of perlite plants to control emissions from perlite milling and expansion sources.

Table 8.17-1 presents emission factors for filterable PM and CO_2 emissions from the expanding and drying processes.

Table 8.17-1 (Metric Units). EMISSION FACTORS FOR PERLITE PROCESSING[a]

Process (SCC)	Filterable PM[b]		CO_2	
	kg/Mg Perlite Expanded	Emission Factor Rating	kg/Mg Perlite Expanded	Emission Factor Rating
Expansion furnace (3-05-018-01)	ND		420[c]	D
Expansion furnace with wet cyclone (3-05-018-01)	1.1[d]	D	NA	
Expansion furnace with cyclone and baghouse (3-05-018-01)	0.15[e]	D	NA	
Dryer (3-05-018-__)	ND		16[f]	D
Dryer with baghouse (3-05-018-__)	0.64[f]	D	NA	
Dryer with cyclones and baghouses (3-05-018-__)	0.13[g]	D	NA	

Table 8.17-1 (English Units). EMISSION FACTORS FOR PERLITE PROCESSING[a]

Process (SCC)	Filterable PM[b]		CO_2	
	lb/ton Perlite Expanded	Emission Factor Rating	lb/ton Perlite Expanded	Emission Factor Rating
Expansion furnace (3-05-018-01)	ND		850[c]	D
Expansion furnace with wet cyclone (3-05-018-01)	2.1[d]	D	NA	
Expansion furnace with cyclone and baghouse (3-05-018-01)	0.29[e]	D	NA	
Dryer (3-05-018-__)	ND		31[f]	D
Dryer with baghouse (3-05-018-__)	1.28[f]	D	NA	
Dryer with cyclones and baghouses (3-05-018-__)	0.25[g]	D	NA	

ND = no data available. NA = not applicable.

[a]All emission factors represent controlled emissions.

[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

[c]Reference 4.

[d]Reference 11.

[e]References 4, 8.

[f]Reference 10.

[g]References 7, 9.

REFERENCES FOR SECTION 8.17

1. *Calciners and Dryers in Mineral Industries -- Background Information for Proposed Standards*, EPA-450/3-85-025a, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1985.

2. Perlite: *US Minerals Yearbook 1989, Volume I: Metals and Minerals*, U. S. Department of the Interior, Bureau of Mines, Washington, DC, pp. 765 - 767.

3. *Perlite Industry Source Category Survey*, EPA-450/3-80-005, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1980.

4. *Emission Test Report (Perlite): W.R. Grace and Company, Irondale, Alabama*, EMB Report 83-CDR-4, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1984.

5. *Particulate Emission Sampling and Analysis: United States Gypsum Company, East Chicago, Indiana*, Environmental Instrument Systems, Inc., South Bend, IN, July 1973.

6. *Air Quality Source Sampling Report #216: Grefco, Inc., Perlite Mill, Socorro, New Mexico*, State of New Mexico Environmental Improvement Division, Santa Fe, NM, January 1982.

7. *Air Quality Source Sampling Report #198: Johns Manville Perlite Plant, No Agua, New Mexico*, State of New Mexico Environmental Improvement Division, Santa Fe, NM, February 1981.

8. *Stack Test Report, Perlite Process: National Gypsum Company, Roll Road, Clarence Center, New York*, Buffalo Testing Laboratories, Buffalo, NY, December 1972.

9. *Particulate Analyses of Dryer and Mill Baghouse Exhaust Emissions at Silbrico Perlite Plant, No Agua, New Mexico*, Kramer, Callahan & Associates, NM, February 1980.

10. *Stack Emissions Survey for U.S. Gypsum, Perlite Mill Dryer Stack, Grants, New Mexico*, File Number EA 7922-17, Ecology Audits, Inc., Dallas, TX, August 1979.

11. *Sampling Observation and Report Review, Grefco, Incorporated, Perlite Insulation Board Plant, Florence, Kentucky*, Commonwealth of Kentucky Department for Natural Resources and Environmental Protection, Bureau of Environmental Protection, Frankfort, KY, January 1979.

8.18 PHOSPHATE ROCK PROCESSING

8.18.1 Process Description[1-5]

The separation of phosphate rock from impurities and nonphosphate materials for use in fertilizer manufacture consists of beneficiation, drying or calcining at some operations, and grinding. The Standard Industrial Classification (SIC) code for phosphate rock processing is 1475. The six-digit Source Classification Code (SCC) for phosphate rock processing is 3-05-019.

Because the primary use of phosphate rock is in the manufacture of phosphatic fertilizer, only those phosphate rock processing operations associated with fertilizer manufacture are discussed here. Florida and North Carolina accounted for 94 percent of the domestic phosphate rock mined and 89 percent of the marketable phosphate rock produced during 1989. Other States in which phosphate rock is mined and processed include Idaho, Montana, Utah, and Tennessee. Alternative flow diagrams of these operations are shown in Figure 8.18-1.

Phosphate rock from the mines is first sent to beneficiation units to separate sand and clay and to remove impurities. Steps used in beneficiation depend on the type of rock. A typical beneficiation unit for separating phosphate rock mined in Florida begins with wet screening to separate pebble rock, which is larger than 1.43 millimeters (mm) (0.056 inch [in.]), or 14 mesh, and smaller than 6.35 mm (0.25 in.) from the balance of the rock. The pebble rock is shipped as pebble product. The material that is larger than 0.85 mm (0.033 in.), or 20 mesh, and smaller than 14 mesh is separated using hydrocyclones and finer mesh screens and is added to the pebble product. The fraction smaller than 20 mesh is treated by two-stage flotation. The flotation process uses hydrophilic or hydrophobic chemical reagents with aeration to separate suspended particles. Phosphate rock mined in North Carolina does not contain pebble rock. In processing this type of phosphate, 2-mm (0.078 in.) or 10-mesh screens are used. Like Florida rock, the fraction that is less than 10 mesh is treated by two-stage flotation, and the fraction larger than 10 mesh is used for secondary road building.

Phosphate rock mined in North Carolina does not contain pebble rock. In processing this type of phosphate, 10-mesh screens are used. Like Florida rock, the fraction that is less than 10 mesh is treated by two-stage flotation, and the fraction larger than 10 mesh is used for secondary road building.

The two major western phosphate rock ore deposits are located in southeastern Idaho and northeastern Utah, and the beneficiation processes used on materials from these deposits differ greatly. In general, southeastern Idaho deposits require crushing, grinding, and classification. Further processing may include filtration and/or drying, depending on the phosphoric acid plant requirements. Primary size reduction generally is accomplished by crushers (impact) and grinding mills. Some classification of the primary crushed rock may be necessary before secondary grinding (rod milling) takes place. The ground material then passes through hydrocyclones that are oriented in a three-stage countercurrent arrangement. Further processing in the form of chemical flotation may be required. Most of the processes are wet to facilitate material transport and to reduce dust.

Northeastern Utah deposits are lower grade and harder than the southeastern Idaho deposits and requiring processing similar to that of the Florida deposits. Extensive crushing and grinding is

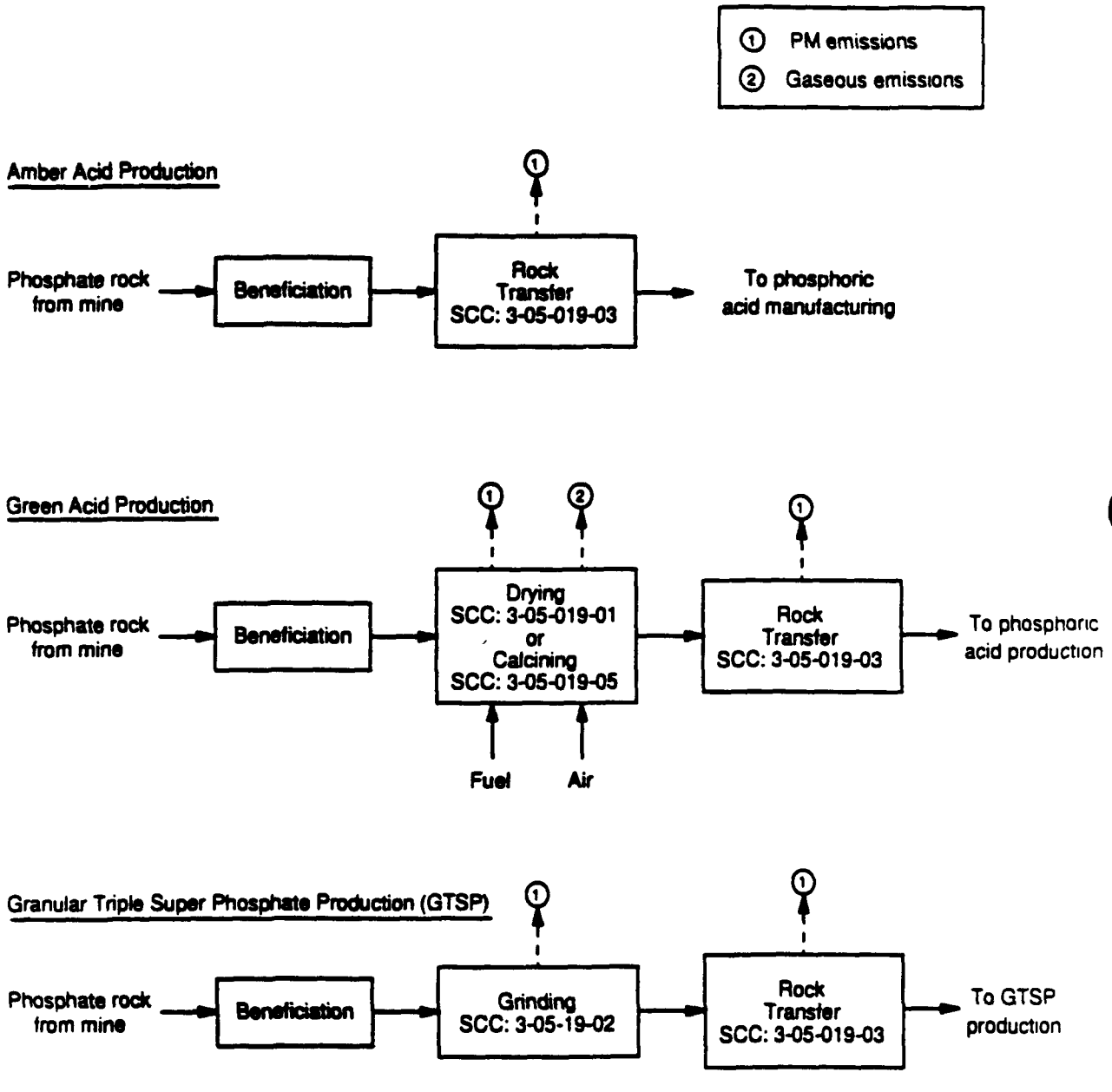


Figure 8.18-1. Alternative process flow diagrams for phosphate rock processing.

necessary to liberate phosphate from the material. The primary product is classified with 150- to 200-mesh screens, and the finer material is disposed of with the tailings. The coarser fraction is processed through multiple steps of phosphate flotation and then diluent flotation. Further processing may include filtration and/or drying, depending on the phosphoric acid plant requirements. As is the case for southeastern Idaho deposits, most of the processes are wet to facilitate material transport and to reduce dust.

The wet beneficiated phosphate rock may be dried or calcined, depending on its organic content. Florida rock is relatively free of organics and is for the most part no longer dried or calcined. The rock is maintained at about 10 percent moisture and is stored in piles at the mine and/or chemical plant for future use. The rock is slurried in water and wet-ground in ball mills or rod mills at the chemical plant. Consequently, there is no significant emission potential from wet grinding. The small amount of rock that is dried in Florida is dried in direct-fired dryers at about 120°C (250°F), where the moisture content of the rock falls from 10 to 15 percent to 1 to 3 percent. Both rotary and fluidized bed dryers are used, but rotary dryers are more common. Most dryers are fired with natural gas or fuel oil (No. 2 or No. 6), with many equipped to burn more than one type of fuel. Unlike Florida rock, phosphate rock mined from other reserves contains organics and must be heated to 760° to 870°C (1400° to 1600°F) to remove them. Fluidized bed calciners are most commonly used for this purpose, but rotary calciners are also used. After drying, the rock is usually conveyed to storage silos on weather-protected conveyors and, from there, to grinding mills. In North Carolina, a portion of the beneficiated rock is calcined at temperatures generally between 800° and 825°C (1480° and 1520°F) for use in "green" phosphoric acid production, which is used for producing super phosphoric acid and as a raw material for purified phosphoric acid manufacturing. To produce "amber" phosphoric acid, the calcining step is omitted, and the beneficiated rock is transferred directly to the phosphoric acid production processes. Phosphate rock that is to be used for the production of granular triple super phosphate (GTSP) is beneficiated, dried, and ground before being transferred to the GTSP production processes.

Dried or calcined rock is ground in roll or ball mills to a fine powder, typically specified as 60 percent by weight passing a 200-mesh sieve. Rock is fed into the mill by a rotary valve, and ground rock is swept from the mill by a circulating air stream. Product size classification is provided by a "revolving whizzer, which is mounted on top of the ball mill," and by an air classifier. Oversize particles are recycled to the mill, and product size particles are separated from the carrying air stream by a cyclone.

8.18.2 Emissions and Controls[1,3-9]

The major emission sources for phosphate rock processing are dryers, calciners, and grinders. These sources emit particulate matter (PM) in the form of fine rock dust and sulfur dioxide (SO_2). Beneficiation has no significant emission potential, because the operations involve slurries of rock and water. The majority of mining operations in Florida handle only the beneficiation step at the mine; all wet grinding is done at the chemical processing facility.

Emissions from dryers depend on several factors, including fuel types, air flow rates, product moisture content, speed of rotation, and the type of rock. The pebble portion of Florida rock receives much less washing than the concentrate rock from the flotation processes. It has a higher clay content and generates more emissions when dried. No significant differences have been noted in gas volume or emissions from fluid bed or rotary dryers. A typical dryer processing 230 megagrams per hour (Mg/hr) (250 tons per hour [tons/hr]) of rock will discharge between 31 and 45 dry normal cubic

meters per second (dry nm^3/sec) (70,000 and 100,000 dry standard cubic feet per minute [dscfm]) of gas, with a PM loading of 1,100 to 11,000 milligrams per nm^3 (mg/nm^3) (0.5 to 5 grains per dry standard cubic feet [gr/dscf]). Emissions from calciners consist of PM and SO_2 and depend on fuel type (coal or oil), air flow rates, product moisture, and grade of rock.

Phosphate rock contains radionuclides in concentrations that are 10 to 100 times the radionuclide concentration found in most natural material. Most of the radionuclides consist of uranium and its decay products. Some phosphate rock also contains elevated levels of thorium and its daughter products. The specific radionuclides of significance include uranium-238, uranium-234, thorium-230, radium-226, radon-222, lead-210, and polonium-210.

The radioactivity of phosphate rock varies regionally, and within the same region the radioactivity of the material may vary widely from deposit to deposit. Table 8.18-1 summarizes data

TABLE 8.18-1. RADIONUCLIDE CONCENTRATIONS OF DOMESTIC PHOSPHATE ROCK[a]

Origin	Typical values, pCi/g
Florida	48 to 143
Tennessee	5.8 to 12.6
South Carolina	267
North Carolina	5.86[b]
Arkansas, Oklahoma	19 to 22
Western States	80 to 123

[a]Reference 8, except where indicated otherwise.
[b]Reference 9.

on radionuclide concentrations for domestic deposits of phosphate rock. Materials handling and processing operations can emit radionuclides either as dust, or in the case of radon-222, which is a decay product of uranium-238, as a gas. Phosphate dust particles generally have the same specific activity as the phosphate rock from which the dust originates.

Scrubbers are most commonly used to control emissions from phosphate rock dryers, but electrostatic precipitators are also used. Fabric filters are not currently being used to control emissions from dryers. Venturi scrubbers with a relatively low pressure loss (3,000 pascals [Pa] [12 in. of water]) may remove 80 to 99 percent of PM 1 to 10 micrometers (μm) in diameter, and 10 to 80 percent of PM less than 1 μm. High-pressure-drop scrubbers (7,500 Pa [30 in. of water]) may have collection efficiencies of 96 to 99.9 percent for PM in the size range of 1 to 10 μm and 80 to 86 percent for particles less than 1 μm. Electrostatic precipitators may remove 90 to 99 percent of all PM. Another control technique for phosphate rock dryers is use of the wet grinding process. In this process, rock is ground in a wet slurry and then added directly to wet process phosphoric acid reactors without drying.

A typical 45 Mg/hr (50 ton/hr) calciner will discharge about 13 to 27 dry nm^3/sec (30,000 to 60,000 dscfm) of exhaust gas, with a PM loading of 0.5 to 5 gr/dscf. As with dryers, scrubbers are

the most common control devices used for calciners. At least one operating calciner is equipped with a precipitator. Fabric filters could also be applied.

Oil-fired dryers and calciners have a potential to emit sulfur oxides when high-sulfur residual fuel oils are burned. However, phosphate rock typically contains about 55 percent lime (CaO), which reacts with the SO_2 to form calcium sulfites and sulfates and thus reduces SO_2 emissions. Dryers and calciners also emit fluorides.

A typical grinder of 45 Mg/hr (50 ton/hr) capacity will discharge about 1.6 to 2.5 dry nm^3/sec (3,500 to 5,500 dscfm) of air containing 0.5 to 5.0 gr/dscf of PM. The air discharged is "tramp air," which infiltrates the circulating streams. To avoid fugitive emissions of rock dust, these grinding processes are operated at negative pressure. Fabric filters, and sometimes scrubbers, are used to control grinder emissions. Substituting wet grinding for conventional grinding would reduce the potential for PM emissions.

Emissions from material handling systems are difficult to quantify because several different systems are used to convey rock. Moreover, a large part of the emission potential for these operations is fugitives. Conveyor belts moving dried rock are usually covered and sometimes enclosed. Transfer points are sometimes hooded and evacuated. Bucket elevators are usually enclosed and evacuated to a control device, and ground rock is generally conveyed in totally enclosed systems with well defined and easily controlled discharge points. Dry rock is normally stored in enclosed bins or silos, which are vented to the atmosphere, with fabric filters frequently used to control emissions.

Table 8.18-2 summarizes emission factors for controlled emissions of SO_2 from phosphate rock calciners and for uncontrolled emissions of CO and CO_2 from phosphate rock dryers and calciners. Emission factors for PM emissions from phosphate rock dryers, grinders, and calciners are presented in Table 8.18-3. Particle size distribution for uncontrolled filterable PM emissions from phosphate rock dryers and calciners are presented in Table 8.18-4. As shown in Table 8.18-4, the size distribution of the uncontrolled calciner emissions is very similar to that of the dryer emissions. Table 8.18-5 summarizes emission factors for emissions of water-soluble and total fluorides from phosphate rock dryers and calciners. Emission factors for controlled and uncontrolled radionuclide emissions from phosphate rock grinders also are presented in Table 8.18-5. Emission factors for PM emissions from phosphate rock ore storage, handling, and transfer can be developed using the equations presented in Section 11.3.

The new source performance standard (NSPS) for phosphate rock plants was promulgated in April 1982 (40 CFR 60 Subpart NN). This standard limits PM emissions and opacity for phosphate rock calciners, dryers, and grinders and limits opacity for handling and transfer operations. The national emission standard for radionuclide emissions from elemental phosphorus plants was promulgated in December 1989 (40 CFR 61 Subpart K). This standard limits emissions of polonium-210 from phosphate rock calciners and nodulizing kilns at elemental phosphorus plants and requires annual compliance tests.

Table 8.18-2 (Metric Units)
EMISSION FACTORS FOR PHOSPHATE ROCK PROCESSING[a]

Process (SCC)	SO_2		CO_2		CO	
	kg/Mg of Total Feed	Emission Factor Rating	kg/Mg of Total Feed	Emissio n Factor Rating	kg/Mg of Total Feed	Emission Factor Rating
Dryer (3-05-019-01)	ND		43[b]	D	0.17[c]	D
Calciner with scrubber (3-05-019-05)	0.0034[d]	D	115[e]	D	ND	

Table 8.18-2 (English Units)
EMISSION FACTORS FOR PHOSPHATE ROCK PROCESSING[a]

Process (SCC)	SO_2		CO_2		CO	
	lb/ton of Total Feed	Emission Factor Rating	lb/ton of Total Feed	Emission Factor Rating	lb/ton of Total Feed	Emission Factor Rating
Dryer (3-05-019-01)	ND		86[b]	D	0.34[c]	D
Calciner with scrubber (3-05-019-05)	0.0069	D	230[e]	D	ND	

ND = no data avaliable.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]References 10, 11.
[c]Reference 10.
[d]References 13, 15.
[e]References 14 to 22.

Table 8.18-3 (Metric Units)
EMISSION FACTORS FOR PHOSPHATE ROCK PROCESSING[a]

Process (SCC)	Filterable PM[b]				Condensible PM[c]			
	PM		PM-10		Inorganic		Organic	
	kg/Mg of Total Feed	Emission Factor Rating	kg/Mg of Total Feed	Emission Factor Rating	kg/Mg of Total Feed	Emission Factor Rating	kg/Mg of Total Feed	Emission Factor Rating
Dryer (3-05-019-01)[d]	2.90	D	2.4	E	ND		ND	
Dryer with scrubber (3-05-019-01)[e]	0.035	D	ND		0.015	D	ND	
Dryer with ESP (3-05-019-01)[d]	0.016	D	ND		0.004	D	ND	
Grinder (3-05-019-02)[d]	0.8	C	ND		ND	D	ND	
Grinder with fabric filter (3-05-019-02)[f]	0.0022	D	ND		0.0011	D	ND	
Calciner (3-05-019-05)[d]	7.7	D	7.4	E	ND		ND	
Calciner with scrubber (3-05-019-05)	0.10[g]	C	ND		0.0079[g]	C	0.044[h]	D
Transfer and storage (3-05-019-__)[d]	2	E	ND		ND		ND	

ND = No data available.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. PM-10 values are based on cascade impaction particle size distribution.
[c]Condensible PM is that PM collected in the impinger portion of a PM sampling train.
[d]Reference 1.
[e]Reference 1, 10, and 11
[f]References 1, 11 and 12
[g]References 1, 14 to 22.
[h]Reference 14 to 22.

Table 8.18-3 (English Units)
EMISSION FACTORS FOR PHOSPHATE ROCK PROCESSING[a]

Process (SCC)	Filterable PM[b]				Condensible PM[c]			
	PM		PM-10		Inorganic		Organic	
	lb/ton of Total Feed	Emission Factor Rating	lb/ton of Total Feed	Emission Factor Rating	lb/ton of Total Feed	Emission Factor Rating	lb/ton of Total Feed	Emission Factor Rating
Dryer (3-05-019-01)[d]	5.70	D	4.8	E	ND		ND	
Dryer with scrubber (3-05-019-01)[e]	0.070	D	ND		0.030	D	ND	
Dryer with ESP (3-05-019-01)[d]	0.033	D	ND		0.008	D	ND	
Grinder (3-05-0190-2)[d]	1.5	C	ND		ND	D	ND	
Grinder with fabric filter (3-05-019-02)[f]	0.0043	D	ND		0.0021	D	ND	
Calciner (3-05-019-05)[d]	15.4	D	15	E	ND		ND	
Calciner with scrubber (3-05-019-05)	0.13[g]	C	ND		0.02	C	0.088[h]	D
Transfer and storage (3-05-019-__)[d]	1	E	ND		ND		ND	

ND = No data available.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. PM-10 values are based on cascade impaction particle size distribution.
[c]Condensible PM is that PM collected in the impinger portion of a PM sampling train.
[d]Reference 1.
[e]References 8, 10 and 11.
[f]References 1, 11, and 12.
[g]References 1, 14 to 22.
[h]References 14 to 22.

Table 8.18-4. PARTICLE SIZE DISTRIBUTION OF FILTERABLE PARTICULATE EMISSIONS FROM PHOSPHATE ROCK DRYERS AND CALCINERS[1]

RATING: E

Diameter, μm	Percent less than size	
	Dryers	Calciners
10	82	96
5	60	81
2	27	52
1	11	26
0.8	7	110
0.5	3	5

Table 8.18-5 (Metric Units)
EMISSION FACTORS FOR PHOSPHATE ROCK PROCESSING[a]

Process (SCC)	Fluoride, H_2O-soluble		Fluoride, total		Radionuclides[b]	
	kg/Mg of Total Feed	Emission Factor Rating	kg/Mg of Total Feed	Emission Factor Rating	kg/Mg of Total Feed	Emission Factor Rating
Dryer (3-05-019-01)[c]	0.0009	D	0.037	D	ND	
Dryer with scrubber (3-05-019-01)[d]	0.00048	D	0.0048	D	ND	
Grinder (3-05-019-02)[e]	ND		ND		800R	E
Grinder with fabric filter (3-05-019-02)[e]	ND		ND		5.2R	E
Calciner with scrubber (3-05-019-05)[f]	ND		0.00081	D	ND	

Table 8.18-5 (English Units)
EMISSION FACTORS FOR PHOSPHATE ROCK PROCESSING[a]

Process (SCC)	Fluoride, H_2O-soluble		Fluoride, total		Radionuclides[b]	
	lb/ton of Total Feed	Emission Factor Rating	lb/ton of Total Feed	Emission Factor Rating	lb/ton of Total Feed	Emission Factor Rating
Dryer (3-05-019-01)[c]	0.0017	D	0.073	D	ND	
Dryer with scrubber (3-05-019-01)[d]	0.00095	D	0.0096	D	ND	
Grinder (3-05-019-02)[e]	ND		ND		730R	E
Grinder with fabric filter (3-05-019-02)[e]	ND		ND		4.7R	E
Calciner with scrubber (3-05-019-05)[f]	ND		0.0016	D	ND	

ND = No data available.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]In units of pCi/Mg of feed.
[c]Reference 10.
[d]References 10 and 11.
[e]References 7 and 8.
[f]Reference 1.

REFERENCES FOR SECTION 8.18

1. *Background Information: Proposed Standards for Phosphate Rock Plants (Draft)*, EPA-450/3-79-017, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1979.

2. *Minerals Yearbook, Volume I, Metals and Minerals*, Bureau of Mines, U. S. Department of the Interior, Washington D.C., 1991.

3. Written communication from B. S. Batts, Florida Phosphate Council, to R. Myers, Emission Inventory Branch, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 12, 1992.

4. Written communication from K. T. Johnson, The Fertilizer Institute, to R. Myers, Emission Inventory Branch, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 30, 1992.

5. Written communication for K. T. Johnson, The Fertilizer Institute to R. Myers, Emission Inventory Branch, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 12, 1989.

6. "Sources of Air Pollution and Their Control," *Air Pollution*, Volume III, 2nd Ed., Arthur Stern, ed., New York, Academic Press, 1968, pp. 221-222.

7. *Background Information Document: Proposed Standards for Radionuclides*, EPA 520/1-83-001, U. S. Environmental Protection Agency, Office of Radiation Programs, Washington, D.C., March 1983.

8. R. T. Stula *et al.*, *Control Technology Alternatives and Costs for Compliance--Elemental Phosphorus Plants, Final Report*, EPA Contract No. 68-01-6429, Energy Systems Group, Science Applications, Incorporated, La Jolla, CA, December 1, 1983.

9. Telephone communication from B. Peacock, Texasgulf, Incorporated, to R. Marinshaw, Midwest Research Institute, Cary, NC, April 4, 1993.

10. *Emission Test Report: International Minerals and Chemical Corporation, Kingsford, Florida*, EMB Report 73-ROC-1, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1973.

11. *Emission Test Report: Occidental Chemical Company, White Springs, Florida*, EMB Report 73-ROC-3, U. S. Environmental Protection Agency, Research Triangle Park, NC, January 1973.

12. *Emission Test Report: International Minerals and Chemical Corporation, Noralyn, Florida*, EMB Report 73-ROC-2, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1973.

13. *Sulfur Dioxide Emission Rate Test, No. 1 Calciner, Texasgulf, Incorporated, Aurora, North Carolina*, Texasgulf Environmental Section, Aurora, NC, May 1990.

14. *Source Performance Test, Calciner Number 4, Texasgulf, Inc., Phosphate Operations, Aurora, NC, August 28, 1991*, Texasgulf, Incorporated, Aurora, NC, September 25, 1991.

15. *Source Performance Test, Calciner Number 6, Texasgulf, Inc., Phosphate Operations, Aurora, NC, August 5 and 6, 1992*, Texasgulf, Incorporated, Aurora, NC, September 17, 1992.

16. *Source Performance Test, Calciner Number 4, Texasgulf, Inc., Phosphate Operations, Aurora, NC, June 30, 1992*, Texasgulf, Incorporated, Aurora, NC, July 16, 1992.

17. *Source Performance Test, Calciner Number 1, Texasgulf, Inc., Phosphate Operations, Aurora, NC, June 10, 1992*, Texasgulf, Incorporated, Aurora, NC, July 8, 1992.

18. *Source Performance Test, Calciner Number 2, Texasgulf, Inc., Phosphate Operations, Aurora, NC, July 7, 1992*, Texasgulf, Incorporated, Aurora, NC, July 16, 1992.

19. *Source Performance Test, Calciner Number 5, Texasgulf, Inc., Phosphate Operations, Aurora, NC, June 16, 1992*, Texasgulf, Incorporated, Aurora, NC, July 8, 1992.

20. *Source Performance Test, Calciner Number 6, Texasgulf, Inc., Phosphate Operations, Aurora, NC, August 4 and 5, 1992*, Texasgulf, Incorporated, Aurora, NC, September 21, 1992.

21. *Source Performance Test, Calciner Number 3, Texasgulf, Inc., Phosphate Operations, Aurora, NC, August 27, 1992*, Texasgulf, Incorporated, Aurora, NC, September 21, 1992.

22. *Source Performance Test, Calciner Number 2, Texasgulf, Inc., Phosphate Operations, Aurora, NC, August 21 and 22, 1992*, Texasgulf, Incorporated, Aurora, NC, September 20, 1992.

8.23 METALLIC MINERALS PROCESSING

8.23.1 Process Description[1-6]

Metallic mineral processing typically involves the mining of ore, from either open pit or underground mines; the crushing and grinding of ore; the separation of valuable minerals from matrix rock through various concentration steps; and at some operations, the drying, calcining, or pelletizing of concentrates to ease further handling and refining. Figure 8.23-1 is a general flow diagram for metallic mineral processing. Very few metallic mineral processing facilities will contain all of the operations depicted in this figure, but all facilities will use at least some of these operations in the process of separating valued minerals from the matrix rock.

The number of crushing steps necessary to reduce ore to the proper size vary with the type of ore. Hard ores, including some copper, gold, iron, and molybdenum ores, may require as much as a tertiary crushing. Softer ores, such as some uranium, bauxite, and titanium/zirconium ores, require little or no crushing. Final comminution of both hard and soft ores is often accomplished by grinding operations using media such as balls or rods of various materials. Grinding is most often performed with an ore/water slurry, which reduces particulate matter emissions to negligible levels. When dry grinding processes are used, particulate matter emissions can be considerable.

After final size reduction, the beneficiation of the ore increases the concentration of valuable minerals by separating them from the matrix rock. A variety of physical and chemical processes is used to concentrate the mineral. Most often, physical or chemical separation is performed in an aqueous environment, which eliminates particulate matter emissions, although some ferrous and titaniferous minerals are separated by magnetic or electrostatic methods in a dry environment.

The concentrated mineral products may be dried to remove surface moisture. Drying is most frequently done in natural gas-fired rotary dryers. Calcining or pelletizing of some products, such as alumina or iron concentrates, is also performed. Emissions from calcining and pelletizing operations are not covered in this section.

8.23.2 Process Emissions[7-9]

Particulate matter emissions result from metallic mineral plant operations such as crushing and dry grinding ore; drying concentrates; storing and reclaiming ores and concentrates from storage bins; transferring materials; and loading final products for shipment. Particulate matter emission factors are provided in Table 8.23-1 for various metallic mineral process operations, including primary, secondary, and tertiary crushing; dry grinding; drying; and material handling and transfer. Fugitive emissions are also possible from roads and open stockpiles, factors for which are in Section 11.2.

The emission factors in Table 8.23-1 are for the process operations as a whole. At most metallic mineral processing plants, each process operation requires several types of equipment. A single crushing operation likely includes a hopper or ore dump, screen(s), crusher, surge bin, apron feeder, and conveyor belt transfer points. Emissions from these various pieces of equipment are often ducted to a single control device. The emission factors provided in Table 8.23-1 for primary,

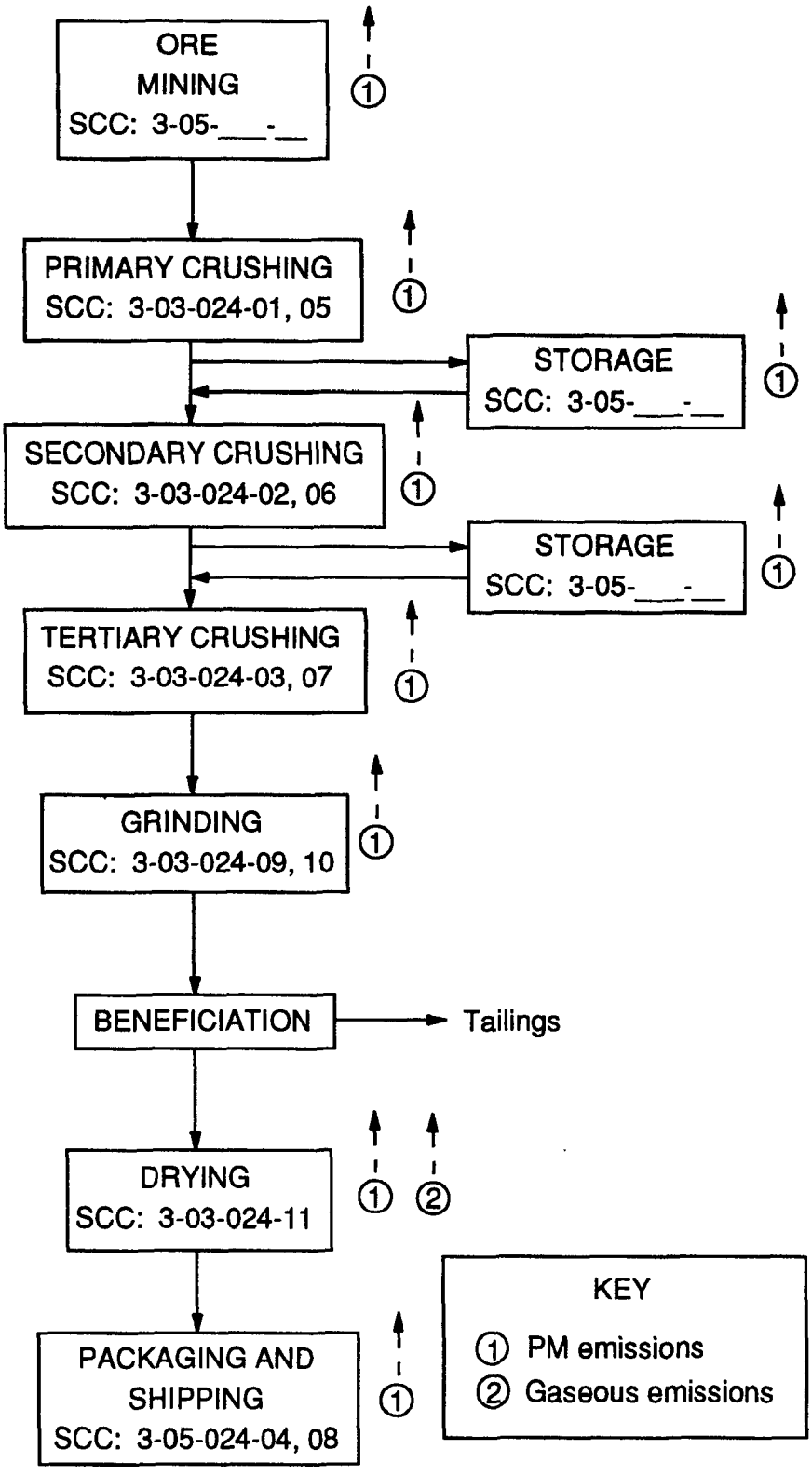


Figure 8.23-1. Process flow diagram for metallic mineral processing.

Table 8.23-1 (Metric Units)
EMISSION FACTORS FOR METALLIC MINERALS PROCESSING[a]

All Emission Factors in the kg/Mg of Material Processed Unless Noted[b]
Ratings (A-E) Follow Each Emission Factor

Source (SCC)	Filterable[c]			
	PM		PM-10	
Low moisture ore[c]				
Primary crushing (3-03-024-01)[d]	0.2	C	0.02	C
Secondary crushing (3-03-024-02)[d]	0.6	D	NA	D
Tertiary crushing (3-03-024-03)[d]	1.4	E	0.08	E
Wet grinding	Neg.		Neg.	
Dry grinding with air conveying and/or air classification (3-03-024-09)[e]	14.4	C	13	C
Dry grinding without air conveying and/or air classification (3-03-024-10)[e]	1.2	D	0.16	D
Drying--all minerals except titanium/zirconium sands (3-03-024-11)[f]	9.8	C	5.9	C
Drying--titanium/zirconium with cyclones (3-03-024-11)[f]	0.3	C	NA	C
Material handling and transfer--all minerals except bauxite (3-03-024-04)[g]	0.06	C	0.03	C
Material handling and transfer--bauxite/alumina (3-03-024-04)[g,h]	0.6	C	NA	
High moisture ore[c]				
Primary crushing (3-03-024-05)[d]	0.01	C	0.004	C
Secondary crushing (3-03-024-06)[d]	0.03	D	0.012	D
Tertiary crushing (3-03-024-07)[d]	0.03	E	0.01	E
Wet grinding	Neg.		Neg.	
Dry grinding with air conveying and/or air classification (3-03-024-09)[e]	14.4	C	13	C
Dry grinding without air conveying and/or air classification (3-03-024-10)[e]	1.2	D	0.16	D
Drying--all minerals except titanium/zirconium sands (3-03-024-11)[f]	9.8	C	5.9	C
Drying--titanium/zirconium with cyclones (3-03-024-11)[f]	0.3	C	NA	C
Material handling and transfer--all minerals except bauxite (3-03-024-08)[g]	0.005	C	0.002	C
Material handling and transfer--bauxite/alumina (3-03-024-08)[g,h]	NA		NA	

NA = not available
Neg. = negligible

[a]References 9 to 12; factors represent uncontrolled emissions unless otherwise noted; controlled emission factors are discussed in Section 8.23.3.

[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.

[c]Defined in Section 8.23.2.

[d]Based on weight of material entering primary crusher.

[e]Based on weight of material entering grinder; emission factors are the same for both low moisture and high moisture ore because material is usually dried before entering grinder.

[f]Based on weight of material exiting dryer; emission factors are the same for both high moisture and low moisture ores; SO_x emissions are fuel dependent (see Chapter 1); NO_x emissions depend on burner design and combustion temperature (see Chapter 1).

[g]Based on weight of material transferred; applies to each loading or unloading operation and to each conveyor belt transfer point.

[h]Bauxite with moisture content as high as 15 to 18 percent can exhibit the emission characteristics of low moisture ore; use low moisture ore emission factor for bauxite unless material exhibits obvious sticky, nondusting characteristics.

Table 8.23-1 (English Units)
EMISSION FACTORS FOR METALLIC MINERALS PROCESSING[a]

All Emission Factors in the lb/ton of Material Processed Unless Noted[b]
Ratings (A-E) Follow Each Emission Factor

Source (SCC)	Filterable[c]			
	PM		PM-10	
Low moisture ore[c]				
Primary crushing (3-03-024-01)[d]	0.5	C	0.05	C
Secondary crushing (303-024-02)[d]	1.2	D	NA	D
Tertiary crushing (3-03-024-03)[d]	2.7	E	0.16	E
Wet grinding	Neg.		Neg.	
Dry grinding with air conveying and/or air classification (3-03-024-09)[e]	28.8	C	26	C
Dry grinding without air conveying and/or air classification (3-03-024-10)[e]	2.4	D	0.31	D
Drying--all minerals except titanium/zirconium sands (3-03-024-11)[f]	19.7	C	12	C
Drying--titanium/zirconium with cyclones (3-03-024-11)[f]	0.5	C	NA	C
Material handling and transfer--all minerals except bauxite (3-03-024-04)[g]	0.12	C	0.06	C
Material handling and transfer--bauxite/alumina (3-03-024-04)[g,h]	1.1	C	NA	
High moisture ore[c]				
Primary crushing (3-03-024-05)[d]	0.02	C	0.009	C
Secondary crushing (3-03-024-06)[d]	0.05	D	0.02	D
Tertiary crushing (3-03-024-07)[d]	0.06	E	0.02	E
Wet grinding	Neg.		Neg.	
Dry grinding with air conveying and/or air classification (3-03-024-09)[e]	28.8	C	26	C
Dry grinding without air conveying and/or air classification (3-03-024-10)[e]	2.4	D	0.31	D
Drying--all minerals except titanium/zirconium sands (3-03-024-11)[f]	19.7	C	12	C
Drying--titanium/zirconium with cyclones (3-03-024-11)[f]	0.5	C	NA	C
Material handling and transfer--all minerals except bauxite (3-03-024-08)[g]	0.01	C	0.004	C
Material handling and transfer--bauxite/alumina (3-03-024-08)[g,h]	NA		NA	

NA = not available
Neg. = negligible
[a]References 9 to 12; factors represent uncontrolled emissions unless otherwise noted; controlled emission factors are discussed in Section 8.23.3.
[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train.
[c]Defined in Section 8.23.2.
[d]Based on weight of material entering primary crusher.
[e]Based on weight of material entering grinder; emission factors are the same for both low moisture and high moisture ore because material is usually dried before entering grinder.
[f]Based on weight of material exiting dryer; emission factors are the same for both high moisture and low moisture ores; SO_x emissions are fuel dependent (see Chapter 1); NO_x emissions depend on burner design and combustion temperature (see Chapter 1).
[g]Based on weight of material transferred; applies to each loading or unloading operation and to each conveyor belt transfer point.
[h]Bauxite with moisture content as high as 15 to 18 percent can exhibit the emission characteristics of low moisture ore; use low moisture ore emission factor for bauxite unless material exhibits obvious sticky, nondusting characteristics.

secondary, and tertiary crushing operations are for process units that are typical arrangements of the above equipment.

Emission factors are provided in Table 8.23-1 for two types of dry grinding operations: those that involve air conveying and/or air classification of material and those that involve screening of material without air conveying. Grinding operations that involve air conveying and air classification usually require dry cyclones for efficient product recovery. The factors in Table 8.23-1 are for emissions after product recovery cyclones. Grinders in closed circuit with screens usually do not require cyclones. Emission factors are not provided for wet grinders because the high moisture content in these operations can reduce emissions to negligible levels.

The emission factors for dryers in Table 8.23-1 include transfer points integral to the drying operation. A separate emission factor is provided for dryers at titanium/zirconium plants that use dry cyclones for product recovery and for emission control. Titanium/zirconium sand-type ores do not require crushing or grinding, and the ore is washed to remove humic and clay material before concentration and drying operations.

At some metallic mineral processing plants, material is stored in enclosed bins between process operations. The emission factors provided in Table 8.23-1 for the handling and transfer of material should be applied to the loading of material into storage bins and the transferring of material from the bin. The emission factor will usually be applied twice to a storage operation: once for the loading operation and once for the reclaiming operation. If material is stored at multiple points in the plant, the emission factor should be applied to each operation and should apply to the material being stored at each bin. The material handling and transfer factors do not apply to small hoppers, surge bins, or transfer points that are integral with crushing, drying, or grinding operations.

At some large metallic mineral processing plants, extensive material transfer operations, with numerous conveyor belt transfer points, may be required. The emission factors for material handling and transfer should be applied to each transfer point that is not an integral part of another process unit. These emission factors should be applied to each such conveyor transfer point and should be based on the amount of material transferred through that point.

The emission factors for material handling can also be applied to final product loading for shipment. Again, these factors should be applied to each transfer point, ore dump, or other point where material is allowed to fall freely.

Test data collected in the mineral processing industries indicate that the moisture content of ore can have a significant effect on emissions from several process operations. High moisture generally reduces the uncontrolled emission rates, and separate emission rates are provided for primary crushers, secondary crushers, tertiary crushers, and material handling and transfer operations that process high-moisture ore. Drying and dry grinding operations are assumed to produce or to involve only low-moisture material.

For most metallic minerals covered in this section, high-moisture ore is defined as ore whose moisture content, as measured at the primary crusher inlet or at the mine, is 4 weight percent or greater. Ore defined as high-moisture at the primary crusher is presumed to be high moisture ore at any subsequent operation for which high moisture factors are provided, unless a drying operation precedes the operation under consideration. Ore is defined as low-moisture when a dryer precedes

the operation under consideration or when the ore moisture at the mine or primary crusher is less than 4 weight percent.

Separate factors are provided for bauxite handling operations because some types of bauxite with a moisture content as high as 15 to 18 weight percent can still produce relatively high emissions during material handling procedures. These emissions could be eliminated by adding sufficient moisture to the ore, but bauxite then becomes so sticky that it is difficult to handle. Thus, there is some advantage to keeping bauxite in a relatively dusty state, and the low-moisture emission factors given represent conditions fairly typical of the industry.

Particulate matter size distribution data for some process operations have been obtained for control device inlet streams. Since these inlet streams contain particulate matter from several activities, a variability has been anticipated in the calculated size-specific emission factors for particulate matter.

Emission factors for particulate matter equal to or less than 10 μm in aerodynamic diameter (PM-10), from a limited number of tests performed to characterize the processes, are presented in Table 8.23-1.

In some plants, particulate matter emissions from multiple pieces of equipment and operations are collected and ducted to a control device. Therefore, examination of reference documents is recommended before applying the factors to specific plants.

Emission factors for PM-10 from high-moisture primary crushing operations and material handling and transfer operations were based on test results usually in the 30 to 40 weight percent range. However, high values were obtained for high-moisture ore at both the primary crushing and the material handling and transfer operations, and these were included in the average values in the table. A similarly wide range occurred in the low-moisture drying operation.

Several other factors are generally assumed to affect the level of emissions from a particular process operation. These include ore characteristics such as hardness, crystal and grain structure, and friability. Equipment design characteristics, such as crusher type, could also affect the emissions level. At this time, data are not sufficient to quantify each of these variables.

8.23.3 Controlled Emissions[7-9]

Emissions from metallic mineral processing plants are usually controlled with wet scrubbers or baghouses. For moderate to heavy uncontrolled emission rates from typical dry ore operations, dryers, and dry grinders, a wet scrubber with pressure drop of 1.5 to 2.5 kilopascals (6 to 10 inches of water) will reduce emissions by approximately 95 percent. With very low uncontrolled emission rates typical of high-moisture conditions, the percentage reduction will be lower (approximately 70 percent).

Over a wide range of inlet mass loadings, a well-designed and maintained baghouse will reduce emissions to a relatively constant outlet concentration. Such baghouses tested in the mineral processing industry consistently reduce emissions to less than 0.05 gram per dry standard cubic meter (g/dscm) (0.02 grains per dry standard cubic foot [gr/dscf]), with an average concentration of 0.015 g/dscm (0.006 gr/dscf). Under conditions of moderate to high uncontrolled emission rates of typical dry ore facilities, this level of controlled emissions represents greater than 99 percent removal

of particulate matter emissions. Because baghouses reduce emissions to a relatively constant outlet concentration, percentage emission reductions would be less for baghouses on facilities with a low level of uncontrolled emissions.

References for Section 8.23

1. D. Kram, "Modern Mineral Processing: Drying, Calcining and Agglomeration", *Engineering and Mining Journal, 181*(6):134-151, June 1980.

2. A. Lynch, *Mineral Crushing and Grinding Circuits*, Elsevier Scientific Publishing Company, New York, 1977.

3. "Modern Mineral Processing: Grinding", *Engineering and Mining Journal, 181*(161):106-113, June 1980.

4. L. Mollick, "Modern Mineral Processing: Crushing", *Engineering and Mining Journal, 181*(6):96-103, June 1980.

5. R. H. Perry, *et al.*, *Chemical Engineer's Handbook*, 4th Ed., McGraw-Hill, New York, 1963.

6. R. Richards and C. Locke, *Textbook of Ore Dressing*, McGraw-Hill, New York, 1940.

7. "Modern Mineral Processing: Air and Water Pollution Controls", *Engineering and Mining Journal, 181*(6):156-171, June 1980.

8. W. E. Horst and R. C. Enochs, "Modern Mineral Processing: Instrumentation and Process Control", *Engineering and Mining Journal, 181*(6):70-92, June 1980.

9. *Metallic Mineral Processing Plants - Background Information for Proposed Standards (Draft).* EPA Contract No. 68-02-3063, TRW, Research Triangle Park, NC, 1981.

10. Telephone communication between E. C. Monnig, TRW, Environmental Division, and R. Beale, Associated Minerals, Inc., May 17, 1982.

11. Written communication from W. R. Chalker, DuPont, Inc., to S. T. Cuffe, U.S. Environmental Protection Agency, Research Triangle Park, NC, December 21, 1981.

12. Written communication from P. H. Fournet, Kaiser Aluminum and Chemical Corporation, to S. T. Cuffe, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 5, 1982.

8.25 LIGHTWEIGHT AGGREGATE MANUFACTURING

8.25.1 Process Description[1,2]

Lightweight aggregate is a type of coarse aggregate that is used in the production of lightweight concrete products such as concrete block, structural concrete, and pavement. The Standard Industrial Classification (SIC) code for lightweight aggregate manufacturing is 3295; there currently is no Source Classification Code (SCC) for the industry.

Most lightweight aggregate is produced from materials such as clay, shale, or slate. Blast furnace slag, natural pumice, vermiculite, and perlite can be used as substitutes, however. To produce lightweight aggregate, the raw material (excluding pumice) is expanded to about twice the original volume of the raw material. The expanded material has properties similar to natural aggregate, but is less dense and therefore yields a lighter concrete product.

The production of lightweight aggregate begins with mining or quarrying the raw material. The material is crushed with cone crushers, jaw crushers, hammermills, or pugmills and is screened for size. Oversized material is returned to the crushers, and the material that passes through the screens is transferred to hoppers. From the hoppers, the material is fed to a rotary kiln, which is fired with coal, coke, natural gas, or fuel oil, to temperatures of about 1200°C (2200°F). As the material is heated, it liquefies and carbonaceous compounds in the material form gas bubbles, which expand the material; in the process, volatile organic compounds (VOC's) are released. From the kiln, the expanded product (clinker) is transferred by conveyor into the clinker cooler, where it is cooled by air, forming a porous material. After cooling, the lightweight aggregate is screened for size; crushed, if necessary; stockpiled; and shipped. Figure 8.25-1 illustrates the lightweight aggregate manufacturing process.

Although the majority (approximately 90 percent) of plants use rotary kilns, traveling grates are also used to heat the raw material. In addition, a few plants process naturally occurring lightweight aggregate such as pumice.

8.25.2 Emissions and Controls[1]

Emissions from the production of lightweight aggregate consist primarily of particulate matter (PM), which is emitted by the rotary kilns, clinker coolers, and crushing, screening, and material transfer operations. Pollutants emitted as a result of combustion in the rotary kilns include sulfur oxides (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), carbon dioxide (CO_2), and VOC's. Chromium, lead, and chlorides also are emitted from the kilns. In addition, other metals, including aluminum, copper, manganese, vanadium, and zinc, are emitted in trace amounts by the kilns. However, emission rates for these pollutants have not been quantified. In addition to PM, clinker coolers emit CO_2 and VOC's. Emission factors for crushing, screening, and material transfer operations can be found in AP-42 Section 8.19.

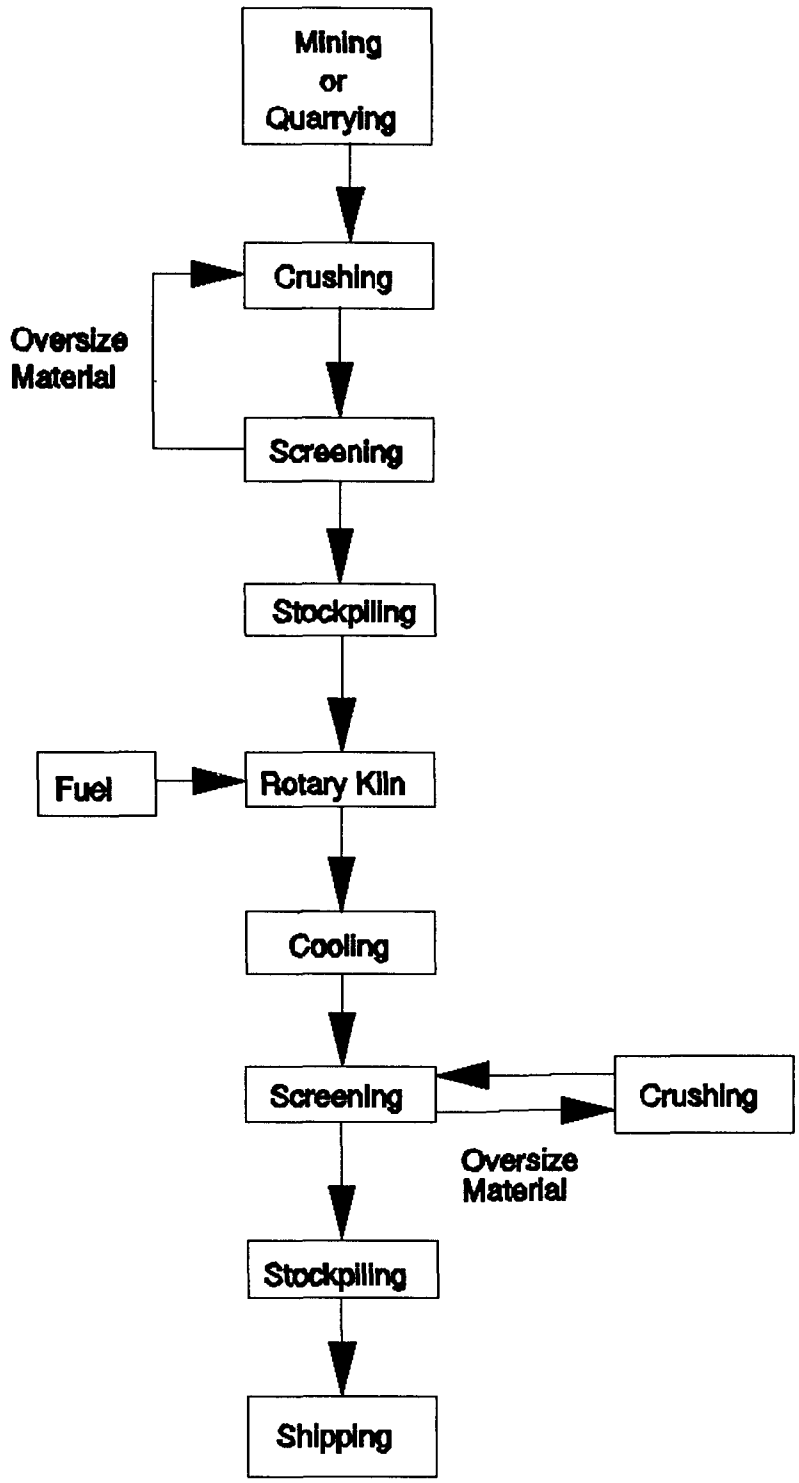


Figure 8.25-1. Process flow diagram for lightweight aggregate manufacturing.

Some lightweight aggregate plants fire kilns with material classified as hazardous waste under the Resource Conservation and Recovery Act. Emission data are available for emissions of hydrogen chloride, chlorine, and several metals from lightweight aggregate kilns burning hazardous waste. However, emission factors developed from these data have not been incorporated in the AP-42 section because the magnitude of emissions of these pollutants is largely a function of the waste fuel composition, which can vary considerably.

Emissions from rotary kilns generally are controlled with wet scrubbers. However, fabric filters and electrostatic precipitators (ESP's) are also used to control kiln emissions. Multiclones and settling chambers generally are the only types of controls for clinker cooler emissions.

Table 8.25-1 summarizes uncontrolled and controlled emission factors for PM emissions (both filterable and condensible) from rotary kilns and clinker coolers. Emission factors for SO_2, NO_x, CO, and CO_2 emissions from rotary kilns are presented in Table 8.25-2. An emission factor for CO_2 emissions from clinker coolers is included in Table 8.25-2. Table 8.25-3 presents emission factors for total VOC (TVOC), emissions from rotary kilns. Size-specific PM emission factors for rotary kilns and clinker coolers are presented in Table 8.25-4.

TABLE 8.25-1 (METRIC UNITS)
EMISSION FACTORS FOR LIGHTWEIGHT AGGREGATE PRODUCTION[a]

Process	Filterable[b]				Condensible PM[c]			
	PM		PM-10		Inorganic		Organic	
	kg/Mg of Feed	Emission Factor Rating	kg/Mg of Feed	Emission Factor Rating	kg/Mg of Feed	Emission Factor Rating	kg/Mg of Feed	Emission Factor Rating
Rotary kiln (3-05)	65[d]	D	ND		0.41[e]	D	0.0080[f]	D
Rotary kiln with scrubber (3-05)	0.39[g]	C	0.15[h]	D	0.10[h]	D	0.0046[h]	D
Rotary kiln with fabric filter (3-05)	0.13[i]	C	ND		0.070[j]	D	ND	
Rotary kiln with ESP (3-05)	0.34[k]	D	ND		0.015[k]	D	ND	
Clinker cooler with settling chamber (3-05)	0.14[l]	D	0.055[l]	D	0.0085[l]	D	0.00034[l]	D
Clinker cooler with multiclone (3-05)	0.15[m]	D	0.060[m]	D	0.0013[m]	D	0.0014[m]	D

ND = No data available.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. PM-10 values are based on cascade impaction particle size distribution.
[c]Condensible PM is that PM collected in the impinger portion of a PM sampling train.
[d]References 3,7,14. Average of 3 tests that ranged from 6.5 to 170 kg/Mg.
[e]Reference 3,14.
[f]Reference 3.
[g]References 3,5,10,12-14.
[h]References 3,5.
[i]References 7,14, 17-19.
[j]Reference 14.
[k]References 15,16.
[l]References 3,6.
[m]Reference 4.

TABLE 8.25-1 (ENGLISH UNITS)
EMISSION FACTORS FOR LIGHTWEIGHT AGGREGATE PRODUCTION[a]

All Emission Factors in Unless Noted
Ratings (A-E) Follow Each Emission Factor

Process (SCC)	Filterable[b]				Condensible PM[c]			
	PM		PM-10		Inorganic		Organic	
	lb/ton of Feed	Emission Factor Rating	lb/ton of Feed	Emission Factor Rating	lb/ton of Feed	Emission Factor Rating	lb/ton of Feed	Emission Factor Rating
Rotary kiln (3-05)	130[d]	D	ND		0.82[e]	D	0.016[f]	D
Rotary kiln with scrubber (3-05)	0.78[g]	C	0.29[h]	D	0.19[h]	D	0.0092[h]	D
Rotary kiln with fabric filter (3-05)	0.26[i]	C	ND		0.14[j]	D	ND	
Rotary kiln with ESP (3-05)	0.67[k]	D	ND		0.031[k]	D	ND	
Clinker cooler with settling chamber (3-05)	0.28[l]	D	0.11[l]	D	0.017[l]	D	0.00067[l]	D
Clinker cooler with multiclone (3-05)	0.30[m]	D	0.12[m]	D	0.0025[m]	D	0.0027[m]	D

ND = No data available.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Filterable PM is that PM collected on or prior to the filter of an EPA Method 5 (or equivalent) sampling train. PM-10 values are based on cascade impaction particle size distribution.
[c]Condensible PM is that PM collected in the impinger portion of a PM sampling train.
[d]References 3,7,14. Average of 3 tests that ranged from 13 to 340 lb/ton.
[e]Reference 3,14.
[f]Reference 3.
[g]References 3,5,10,12-14.
[h]References 3,5.
[i]References 7,14, 17-19.
[j]Reference 14.
[k]References 15,16.
[l]References 3,6.
[m]Reference 4.

Table 8.25-2 (Metric Units)
EMISSION FACTORS FOR LIGHTWEIGHT AGGREGATE PRODUCTION[a]

Process (SCC)	SO_x		NO_x		CO		CO_2	
	kg/Mg of Product	Emission Factor Rating	kg/Mg of Product	Emission Factor Rating	kg/Mg of Product	Emission Factor Rating	kg/Mg of Product	Emission Factor Rating
Rotary kiln (3-05)	2.8[b]	C	ND		0.29[c]	C	240[d]	C
Rotary kiln with scrubber (3-05)	1.7[e]	C	1.0[f]	D	ND		ND	
Clinker cooler with dry multicyclone (3-05)	ND		ND		ND		22[g]	D

TABLE 8.25-2 (ENGLISH UNITS)
EMISSION FACTORS FOR LIGHTWEIGHT AGGREGATE PRODUCTION[a]

Process (SCC)	SO_x		NO_x		CO		CO_2	
	lb/ton of Product	Emission Factor Rating	lb/ton of Product	Emission Factor Rating	lb/ton of Product	Emission Factor Rating	lb/ton of Product	Emission Factor Rating
Rotary kiln (3-05)	5.6[b]	C	ND		0.59[c]	C	480[d]	C
Rotary kiln with scrubber (3-05)	3.4[e]	C	1.9[f]	D	ND		ND	
Clinker cooler with dry multicyclone (3-05)	ND		ND		ND		43[g]	D

ND = No data available.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]References 3, 4, 5, 8.
[c]References 17, 18, 19.
[d]References 3, 4, 5, 12, 13, 14, 17, 18, 19
[e]References 3, 4, 5, 9.
[f]References 3, 4, 5.
[g]Reference 4.

TABLE 8.25-3 (METRIC UNITS)
EMISSION FACTORS FOR LIGHTWEIGHT AGGREGATE PRODUCTION[a]

Process (SCC)	TVOC's	
	kg/Mg of Product	Emission Factor Rating
Rotary kiln (3-05)	ND	
Rotary kiln with scrubber (3-05)	0.39[b]	D

TABLE 8.25-3 (ENGLISH UNITS)
EMISSION FACTORS FOR LIGHTWEIGHT AGGREGATE PRODUCTION[a]

All Emission Factors in Unless Noted
Ratings (A-E) Follow Each Emission Factor

Process (SCC)	TVOC's	
	lb/ton of Product	Emission Factor Rating
Rotary kiln (3-05)	ND	
Rotary kiln with scrubber (3-05)	0.78[b]	D

ND = No data available.
[a]Factors represent uncontrolled emissions unless otherwise noted.
[b]Reference 3.

TABLE 8.25-4. PARTICULATE MATTER SIZE-SPECIFIC EMISSION FACTORS FOR EMISSIONS FROM ROTARY KILNS AND CLINKER COOLERS[a]

Rotary Kiln with Scrubber[b]
EMISSION FACTOR RATING: D

Diameter, microns	Cumulative % less than diameter	Emission factor	
		kg/Mg	lb/ton
2.5	35	0.10	0.20
6.0	46	0.13	0.26
10.0	50	0.14	0.28
15.0	55	0.16	0.31
20.0	57	0.16	0.32

Clinker Cooler with Settling Chamber[c]
EMISSION FACTOR RATING: D

Diameter, microns	Cumulative % less than diameter	Emission factor	
		kg/Mg	lb/ton
2.5	9	0.014	0.027
6.0	21	0.032	0.063
10.0	35	0.055	0.11
15.0	49	0.080	0.16
20.0	58	0.095	0.19

Clinker Cooler with Multiclone[d]
EMISSION FACTOR RATING: D

Diameter, microns	Cumulative % less than diameter	Emission factor	
		kg/Mg	lb/ton
2.5	19	0.029	0.057
6.0	31	0.047	0.093
10.0	40	0.060	0.12
15.0	48	0.072	0.14
20.0	53	0.080	0.16

[a]Emission factors based on total feed.
[b]References 3, 5.
[c]References 3, 6.
[d]Reference 4.

REFERENCES FOR SECTION 8.25

1. *Calciners and Dryers in Mineral Industries-Background Information for Proposed Standards*, EPA-450/3-85-025a, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1985.

2. B. H. Spratt, *The Structural Use of Lightweight Aggregate Concrete*, Cement and Concrete Association, United Kingdom, 1974.

3. *Emission Test Report: Vulcan Materials Company, Bessemer, Alabama*, EMB Report 80-LWA-4, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1982.

4. *Emission Test Report: Arkansas Lightweight Aggregate Corporation, West Memphis, Arkansas*, EMB Report 80-LWA-2, U. S. Environmental Protection Agency, Research Triangle Park, NC, May 1981.

5. *Emission Test Report: Plant K6*, from *Calciners and Dryers in Mineral Industries - Background Information Standards*, EPA-450/3-85-025a, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1985.

6. *Emission Test Report: Galite Corporation, Rockmart, Georgia*, EMB Report 80-LWA-6, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1982.

7. *Summary of Emission Measurements on No. 5 Kiln, Carolina Solite Corporation, Aquadale, North Carolina*, Sholtes & Koogler Environmental Consultants, Inc., Gainesville, FL, April 1983.

8. *Sulfur Dioxide Emission Measurements, Lightweight Aggregate Kiln No. 5 (Inlet), Carolina Solite Corporation, Aquadale, North Carolina*, Sholtes & Koogler Environmental Consultants, Inc., Gainesville, FL, May 1991.

9. *Sulfur Dioxide Emission Measurements, Lightweight Aggregate Kiln No. 5 (Outlet), Carolina Solite Corporation, Aquadale, North Carolina*, Sholtes & Koogler Environmental Consultants, Inc., Gainesville, FL, May 1991.

10. *Summary of Particulate Matter Emission Measurements, No. 5 Kiln Outlet, Florida Solite Corporation, Green Cove Springs, Florida*, Sholtes and Koogler Environmental Consultants, Gainesville, FL, June 19, 1981.

11. *Summary of Particulate Matter Emission Measurements, No. 5 Kiln Outlet, Florida Solite Corporation, Green Cove Springs, Florida*, Sholtes and Koogler Environmental Consultants, Gainesville, FL, September 3, 1982.

12. *Particulate Emission Source Test Conducted on No.1 Kiln Wet Scrubber at Tombigbee Lightweight Aggregate Corporation, Livingston, Alabama*, Resource Consultants, Brentwood, TN, November 12, 1981.

13. *Particulate Emission Source Test Conducted on No.2 Kiln Wet Scrubber at Tombigbee Lightweight Aggregate Corporation, Livingston, Alabama*, Resource Consultants, Brentwood, TN, November 12, 1981.

14. *Report of Simultaneous Efficiency Tests Conducted on the Orange Kiln and Baghouse at Carolina Stalite, Gold Hill, N.C.*, Rossnagel & Associates, Charlotte, NC, May 9, 1980.

15. *Stack Test Report No. 85-1, Lehigh Lightweight Aggregate Plant, Dryer-Kiln No. 2, Woodsboro, Maryland*, Division of Stationary Source Enforcement, Maryland Department of Health and Mental Hygiene, Baltimore, MD, February 1, 1985.

16. *Stack Test Report No. 85-7, Lehigh Lightweight Aggregate Plant, Dryer-Kiln No. 1, Woodsboro, Maryland*, Division of Stationary Source Enforcement, Maryland Department of Health and Mental Hygiene, Baltimore, MD, May 1985.

17. *Emission Test Results for No. 2 and No. 4 Aggregate Kilns, Solite Corporation, Leaksville Plant, Cascade, Virginia*, IEA, Research Triangle Park, NC, August 8, 1992.

18. *Emission Test Results for No. 2 Aggregate Kiln, Solite Corporation, Hubers Plant, Brooks, Kentucky*, IEA, Research Triangle Park, NC, August 12, 1992.

19. *Emission Test Results for No. 7 and No. 8 Aggregate Kilns, Solite Corporation, A. F. Old Plant, Arvonia, Virginia*, IEA, Research Triangle Park, NC, August 8, 1992.

8.27 FELDSPAR PROCESSING

8.27.1 General[1]

Feldspar consists essentially of aluminum silicates combined with varying percentages of potassium, sodium, and calcium, and it is the most abundant mineral of the igneous rocks. The two types of feldspar are soda feldspar (7 percent or higher Na_2O) and potash feldspar (8 percent or higher K_2O). Feldspar-silica mixtures can occur naturally, such as in sand deposits, or can be obtained from flotation of mined and crushed rock.

8.27.2 Process Description [1-2]

Conventional open-pit mining methods including removal of overburden, drilling and blasting, loading, and transport by trucks are used to mine ores containing feldspar. A froth flotation process is used for most feldspar ore beneficiation. Figure 8.27-1 shows a process flow diagram of the flotation process. The ore is crushed by primary and secondary crushers and ground by jaw crushers, cone crushers, and rod mills until it is reduced to less than 841 μm (20 mesh). Then the ore passes to a three-stage, acid-circuit flotation process.

An amine collector that floats off and removes mica is used in the first flotation step. Also, sulfuric acid, pine oil, and fuel oil are added. After the feed is dewatered in a classifier or cyclone to remove reagents, sulfuric acid is added to lower the pH. Petroleum sulfonate (mahogany soap) is used to remove iron-bearing minerals. To finish the flotation process, the discharge from the second flotation step is dewatered again, and a cationic amine is used for collection as the feldspar is floated away from quartz in an environment of hydrofluoric acid (pH of 2.5 to 3.0).

If feldspathic sand is the raw material, no size reduction may be required. Also, if little or no mica is present, the first flotation step may be bypassed. Sometimes the final flotation stage is omitted, leaving a feldspar-silica mixture (often referred to as sandspar), which is usually used in glassmaking.

From the completed flotation process, the feldspar float concentrate is dewatered to 5 to 9 percent moisture. A rotary dryer is then used to reduce the moisture content to 1 percent or less. Rotary dryers are the most common dryer type used, although fluid bed dryers are also used. Typical rotary feldspar dryers are fired with No. 2 oil or natural gas, operate at about 230°C (450°F), and have a retention time of 10 to 15 minutes. Magnetic separation is used as a backup process to remove any iron minerals present. Following the drying process, dry grinding is sometimes performed to reduce the feldspar to less than 74 μm (200 mesh) for use in ceramics, paints, and tiles. Drying and grinding are often performed simultaneously by passing the dewatered cake through a rotating gas-fired cylinder lined with ceramic blocks and charged with ceramic grinding balls. Material processed in this manner must then be screened for size or air classified to ensure proper particle size.

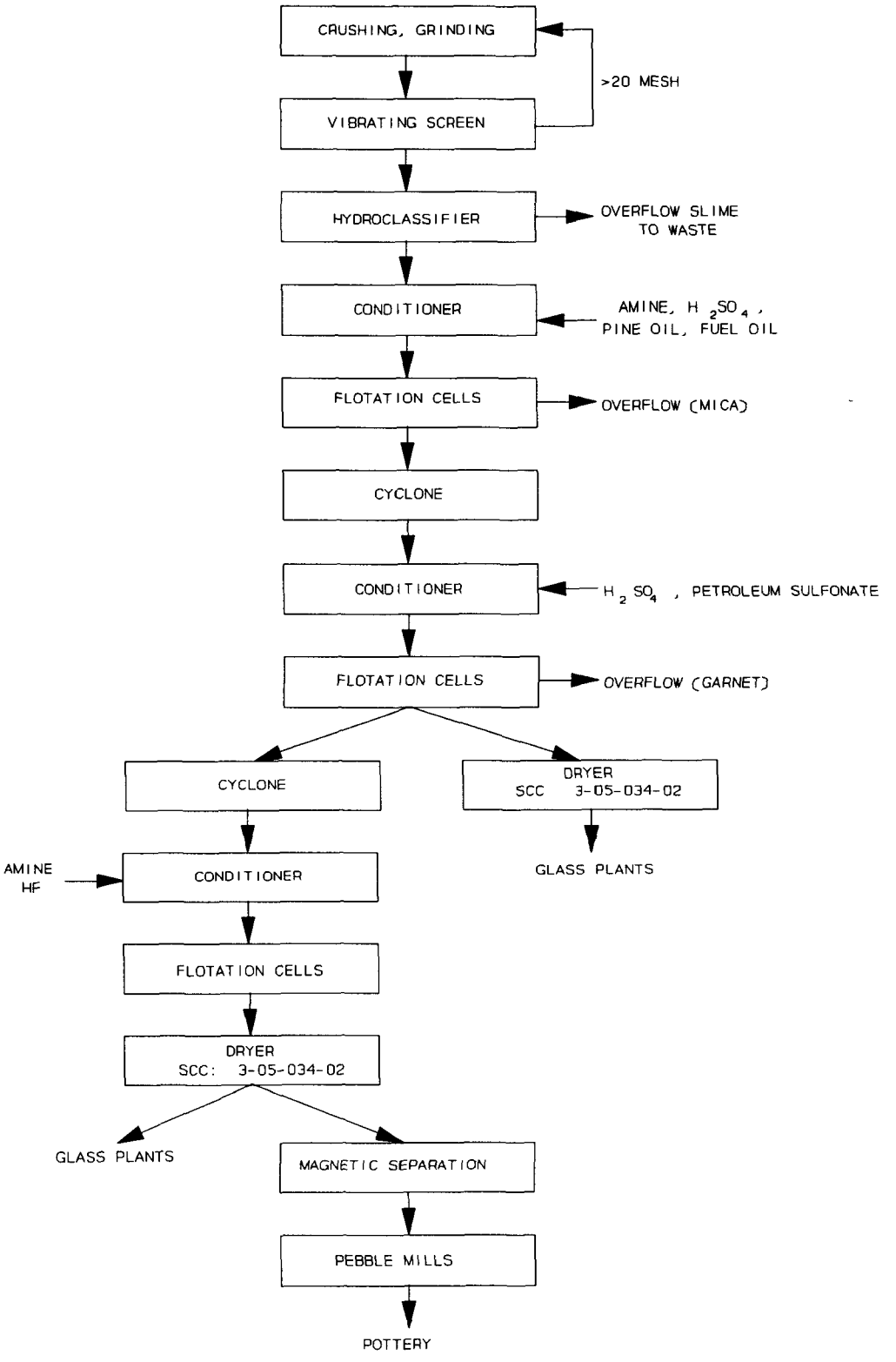


Figure 8.27-1. Feldspar flotation process.[1]

8.27.2 Emissions and Controls

The primary pollutant of concern that is emitted from feldspar processing is particulate matter (PM). Particulate matter is emitted by several feldspar processing operations, including crushing, grinding, screening, drying, and materials handling and transfer operations.

Emissions from dryers typically are controlled by a combination of a cyclone or a multiclone and a scrubber system. Particulate matter emissions from crushing and grinding generally are controlled by fabric filters.

Table 8.27-1 presents controlled emission factors for filterable PM from the drying process. Table 8.27-2 presents emission factors for CO_2 from the drying process. The controls used in feldspar processing achieve only incidental control of CO_2.

Table 8.27-1 (Metric Units).
EMISSION FACTORS FOR FILTERABLE PARTICULATE MATTER[a]

Process (SCC)	Filterable Particulate	
	kg/Mg Feldspar Dried	Emission Factor Rating
Dryer with scrubber and demister[b] (SCC 3-05-034-02)	0.60	D
Dryer with mechanical collector and scrubber[c,d] (SCC 3-05-034-02)	0.041	D

Table 8.27-1 (English Units).
EMISSION FACTORS FOR FILTERABLE PARTICULATE MATTER[a]

Process (SCC)	Filterable Particulate	
	lb/Ton Feldspar Dried	Emission Factor Rating
Dryer with scrubber[b] (SCC 3-05-034-02)	1.2	D
Dryer with mechanical collector and scrubber[c,d] (SCC 3-05-034-02)	0.081	D

[a] SCC = Source Classification Code
[b] Reference 4.
[c] Reference 3.
[d] Reference 5.

Table 8.27-2 (Metric Units).
EMISSION FACTOR FOR CARBON DIOXIDE[a]

Process (SCC)	Carbon Dioxide	
	kg/Mg Feldspar Dried	Emission Factor Rating
Dryer with multiclone and scrubber[b] (SCC 3-05-034-02)	51	D

Table 8.27-2 (English Units).
EMISSION FACTOR FOR CARBON DIOXIDE[a]

Process (SCC)	Carbon Dioxide	
	lb/Ton Feldspar Dried	Emission Factor Rating
Dryer with multiclone and scrubber[b] (SCC 3-05-034-02)	102	D

[a] SCC = Source Classification Code.
[b] Scrubbers may achieve incidental control of CO_2 emissions. Multiclones do not control CO_2 emissions.

REFERENCES FOR SECTION 8.27

1. *Calciners and Dryers in Mineral Industries--Background Information for Proposed Standards*, EPA-450/3-85-025a, U.S. Environmental Protection Agency, Research Triangle Park, NC, October 1985.

2. *US Minerals Yearbook 1989:* Feldspar, Nepheline syenite, and Aplite: US Minerals Yearbook 1989, pp. 389-396.

3. *Source Sampling Report for The Feldspar Corporation: Spruce Pine, NC*, Environmental Testing Inc., Charlotte, NC, May 1979.

4. *Particulate Emission Test Report for a Scrubber Stack at International Minerals Corporation: Spruce Pine, NC*, North Carolina Department of Natural Resources & Community Development, Division of Environmental Management, September 1981.

5. *Particulate Emission Test Report for Two Scrubber Stacks at Lawson United Feldspar & Mineral Company: Spruce Pine, NC*, North Carolina Department of Natural Resources & Community Development, Division of Environmental Management, October 1978.

STORAGE OF ORGANIC LIQUIDS

12.1 PROCESS DESCRIPTION[1,2]

Storage vessels containing organic liquids can be found in many industries, including (1) petroleum producing and refining, (2) petrochemical and chemical manufacturing, (3) bulk storage and transfer operations, and (4) other industries consuming or producing organic liquids. Organic liquids in the petroleum industry, usually called petroleum liquids, generally are mixtures of hydrocarbons having dissimilar true vapor pressures (for example, gasoline and crude oil). Organic liquids in the chemical industry, usually called volatile organic liquids, are composed of pure chemicals or mixtures of chemicals with similar true vapor pressures (for example, benzene or a mixture of isopropyl and butyl alcohols).

Five basic tank designs are used for organic liquid storage vessels: fixed roof (vertical and horizontal), external floating roof, internal floating roof, variable vapor space, and pressure (low and high). A brief description of each tank is provided below. Loss mechanisms associated with each type of tank are provided in Section 12.2.

The emission estimating equations presented in Chapter 12 were developed by the American Petroleum Institute (API). API retains the copyright to these equations. API has granted permission for the nonexclusive; noncommercial distribution of this material to governmental and regulatory agencies. However, API reserves its rights regarding all commercial duplication and distribution of its material. Therefore, the material presented in Chapter 12 is available for public use, but the material cannot be sold without written permission from the American Petroleum Institute and the U. S. Environmental Protection Agency.

Fixed Roof Tanks - A typical vertical fixed roof tank is shown in Figure 12.1-1. This type of tank consists of a cylindrical steel shell with a permanently affixed roof, which may vary in design from cone- or dome-shaped to flat.

Fixed roof tanks are either freely vented or equipped with a pressure/vacuum vent. The latter allows them to operate at a slight internal pressure or vacuum to prevent the release of vapors during very small changes in temperature, pressure, or liquid level. Of current tank designs, the fixed roof tank is the least expensive to construct and is generally considered the minimum acceptable equipment for storing organic liquids.

Horizontal fixed roof tanks are constructed for both above-ground and underground service and are usually constructed of steel, steel with a fiberglass overlay, or fiberglass-reinforced polyester. Horizontal tanks are generally small storage tanks with capacities of less than 40,000 gallons. Horizontal tanks are constructed such that the length of the tank is not greater than six times the diameter to ensure structural integrity. Horizontal tanks are usually equipped with pressure-vacuum vents, gauge hatches and sample wells, and manholes to provide access to these tanks. In addition, underground tanks are cathodically protected to prevent corrosion of the tank shell. Cathodic protection is accomplished by placing

sacrificial anodes in the tank that are connected to an impressed current system or by using galvanic anodes in the tank.

The potential emission sources for above-ground horizontal tanks are the same as those for vertical fixed roof tanks. Emissions from underground storage tanks are associated mainly with changes in the liquid level in the tank. Losses due to changes in temperature or barometric pressure are minimal for underground tanks because the surrounding earth limits the diurnal temperature change, and changes in the barometric pressure result in only small losses.

External Floating Roof Tanks - A typical external floating roof tank consists of an open-topped cylindrical steel shell equipped with a roof that floats on the surface of the stored liquid. Floating roof tanks that are currently in use are constructed of welded steel plate and are of two general types: pontoon or double-deck. Pontoon-type and double-deck-type external floating roofs are shown in Figures 12.1-2 and 12.1-3, respectively. With all types of external floating roof tanks, the roof rises and falls with the liquid level in the tank. External floating roof tanks are equipped with a seal system, which is attached to the roof perimeter and contacts the tank wall. The purpose of the floating roof and seal system is to reduce evaporative loss of the stored liquid. Some annular space remains between the seal system and the tank wall. The seal system slides against the tank wall as the roof is raised and lowered. The floating roof is also equipped with roof fittings that penetrate the floating roof and serve operational functions. The external floating roof design is such that evaporative losses from the stored liquid are limited to losses from the seal system and roof fittings (standing storage loss) and any exposed liquid on the tank walls (withdrawal loss).

Internal Floating Roof Tanks - An internal floating roof tank has both a permanent fixed roof and a floating deck inside. The terms "deck" and "floating roof" can be used interchangeably in reference to the structure floating on the liquid inside the tank. There are two basic types of internal floating roof tanks: tanks in which the fixed roof is supported by vertical columns within the tank, and tanks with a self-supporting fixed roof and no internal support columns. Fixed roof tanks that have been retrofitted to use a floating deck are typically of the first type. External floating roof tanks that have been converted to internal floating roof tanks typically have a self-supporting roof. Newly constructed internal floating roof tanks may be of either type. The deck in internal floating roof tanks rises and falls with the liquid level and either floats directly on the liquid surface (contact deck) or rests on pontoons several inches above the liquid surface (noncontact deck). The majority of aluminum internal floating roofs currently in service are noncontact decks. Typical contact deck and noncontact deck internal floating roof tanks are shown in Figure 12.1-4.

Contact decks can be (1) aluminum sandwich panels that are bolted together, with a honeycomb aluminum core floating in contact with the liquid; (2) pan steel decks floating in contact with the liquid, with or without pontoons; and (3) resin-coated, fiberglass reinforced polyester (FRP), buoyant panels floating in contact with the liquid. The majority of internal contact floating roofs currently in service are aluminum sandwich panel-type or pan steel-type. The FRP roofs are less common. The panels of pan steel decks are usually welded together.

Typical noncontact decks have an aluminum deck and an aluminum grid framework supported above the liquid surface by tubular aluminum pontoons or some other buoyant structure. The noncontact decks usually have bolted deck seams. Installing a floating roof or deck minimizes evaporative losses of the stored liquid. As with the external floating roof tanks, both contact and noncontact decks incorporate rim seals and deck fittings for the same purposes previously described for external floating roof tanks. Evaporation losses from decks may come from deck fittings, nonwelded deck seams, and the annular space between the deck and tank wall. In addition, these tanks are freely vented by circulation vents at the top of the fixed roof. The vents minimize the possibility of organic vapor accumulation in concentrations approaching the flammable range. An internal floating roof tank not freely vented is considered a pressure tank. Emission estimation methods for such tanks are not provided in AP-42.

Variable Vapor Space Tanks - Variable vapor space tanks are equipped with expandable vapor reservoirs to accommodate vapor volume fluctuations attributable to temperature and barometric pressure changes. Although variable vapor space tanks are sometimes used independently, they are normally connected to the vapor spaces of one or more fixed roof tanks. The two most common types of variable vapor space tanks are lifter roof tanks and flexible diaphragm tanks.

Lifter roof tanks have a telescoping roof that fits loosely around the outside of the main tank wall. The space between the roof and the wall is closed by either a wet seal, which is a trough filled with liquid, or a dry seal, which uses a flexible coated fabric.

Flexible diaphragm tanks use flexible membranes to provide expandable volume. They may be either separate gasholder units or integral units mounted atop fixed roof tanks.

Variable vapor space tank losses occur during tank filling when vapor is displaced by liquid. Loss of vapor occurs only when the tank's vapor storage capacity is exceeded.

Pressure Tanks - Two classes of pressure tanks are in general use: low pressure (2.5 to 15 psig) and high pressure (higher than 15 psig). Pressure tanks generally are used for storing organic liquids and gases with high vapor pressures and are found in many sizes and shapes, depending on the operating pressure of the tank. Pressure tanks are equipped with a pressure/vacuum vent that is set to prevent venting loss from boiling and breathing loss from daily temperature or barometric pressure changes. High-pressure storage tanks can be

operated so that virtually no evaporative or working losses occur. In low-pressure tanks, working losses can occur with atmospheric venting of the tank during filling operations. No appropriate correlations are available to estimate vapor losses from pressure tanks.

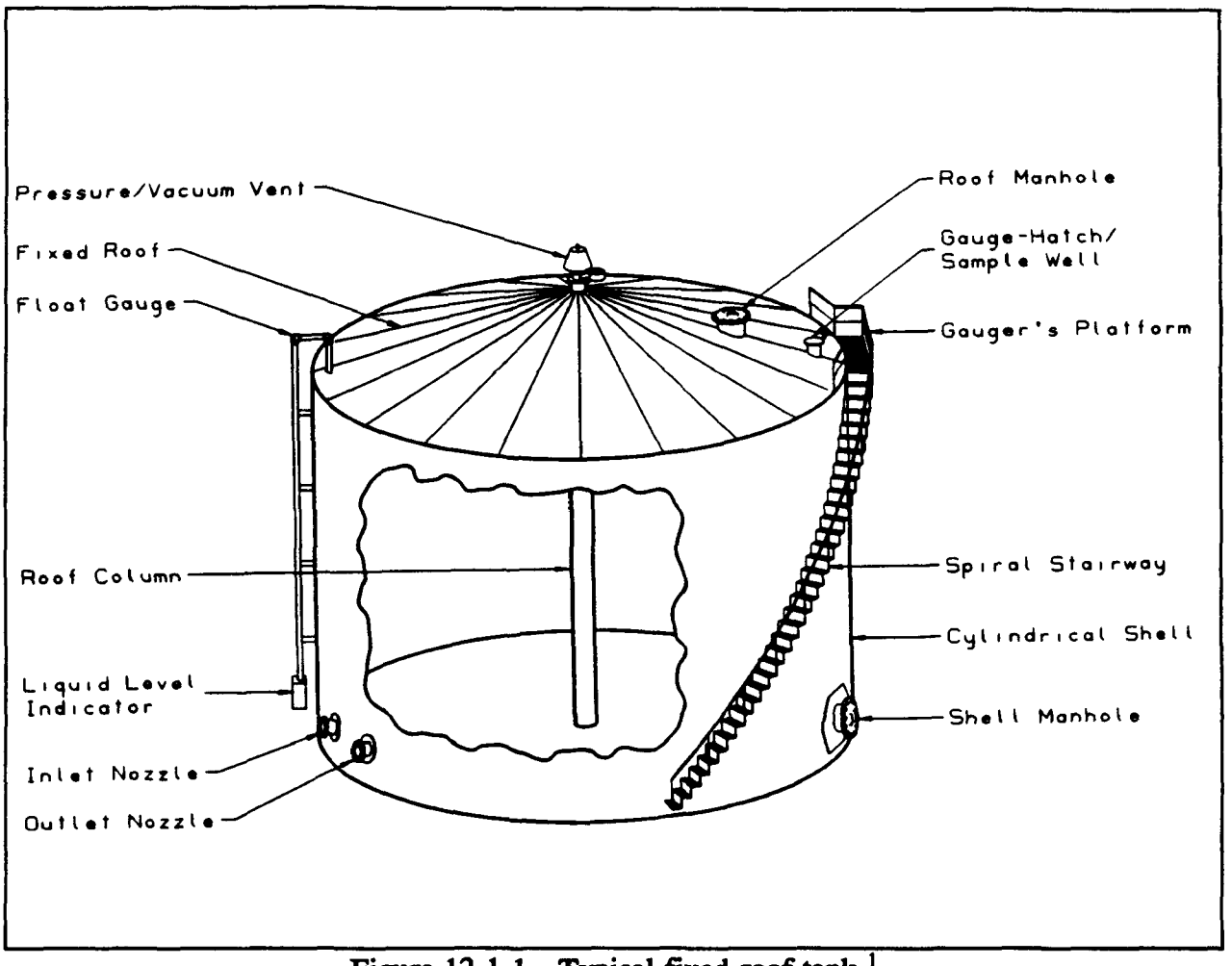


Figure 12.1-1. Typical fixed-roof tank.[1]

TABLE 12.3-2. PROPERTIES (M_V, W_{VC}, P_{VA}, W_L) OF SELECTED PETROLEUM LIQUIDS[a]

Petroleum liquid	Vapor molecular weight (at 60°F) M_V (lb/lb-mole)	Condensed vapor density (at 60°F) W_{VC} (lb/gal)	Liquid density, lb/gal at 60°F	True vapor pressure in psi at						
				40°C	50°F	60°F	70°F	80°F	90°F	100°F
Gasoline RVP 13	62	4.9	4.9	4.7	5.7	6.9	8.3	9.9	11.7	13.8
Gasoline RVP 10	66	5 1	5.1	3.4	4.2	5.2	6.2	7.4	8.8	10.5
Gasoline RVP 7	68	5.2	5.2	2.3	2.9	3.5	4.3	5.2	6.2	7.4
Crude Oil RVP 5	50	4.5	4.5	1.8	2.3	2.8	3.4	4.0	4.8	5.7
Jet naphtha (JP-4)	80	5.4	5.4	0.8	1.0	1.3	1.6	1.9	2.4	2.7
Jet kerosene	130	6.1	6.1	0.0041	0.0060	0.0085	0.011	0.015	0.021	0.029
Distillate fuel oil No. 2	130	6.1	6.1	0.0031	0.0045	0.0074	0.0090	0.012	0.016	0.022
Residual oil No. 6	190	6.4	6.4	0.00002	0.00003	0.00004	0.00006	0.00009	0.00013	0.00019

Notes:
[a]References 7 and 8.

TABLE 12.3-3. PHYSICAL PROPERTIES OF SELECTED PETROCHEMICALS[a]

Name	Formula	Molecular weight	Boiling point at 1 atmosphere (°F)	Liquid density at 60°F(pounds per gallon)	Vapor pressure (pounds per square inch absolute) at						
					40°F	50°F	60°F	70°F	80°F	90°F	100°F
Acetone	CH_3COCH_3	58.08	133.0	6.628	1.682	2.185	2.862	3.713	4.699	5.917	7.251
Acetonitrile	CH_3CN	41.05	178.9	6.558	0.638	0.831	1.083	1.412	1.876	2.456	3.133
Acrylonitrile	CH_2:CHCN	53.06	173.5	6.758	0.812	0.967	1.373	1.799	2.378	3.133	4.022
Allyl alcohol	CH_2:$CHCH_2OH$	58.08	206.6	7.125	0.135	0.193	0.261	0.387	0.522	0.716	1.006
Allyl chloride	CH_2:$CHCH_2Cl$	76.53	113.2	7.864	2.998	3.772	4.797	6.015	7.447	9.110	11.025
Ammonium hydroxide (28.8% solution)	NH_4OH--H_2O	35.05	83.0	7.481	5.130	6.630	8.480	10.760	13.520	16.760	20.680
Benzene	C_6H_6	78.11	176.2	7.365	0.638	0.870	1.160	1.508	1.972	2.610	3.287
iso-Butyl alcohol	$(CH_3)_2CHCH_2OH$	74.12	227.1	6.712	0.058	0.097	0.135	0.193	0.271	0.387	0.541
tert-Butyl alcohol	$(CH_3)_3COH$	74.12	180.5	6.595	0.174	0.290	0.425	0.638	0.909	1.238	1.702
n-Butyl chloride	$CH_3CH_2CH_2CH_2Cl$	92.57	172.0	7.430	0.715	1.006	1.320	1.740	2.185	2.684	3.481
Carbon disulfide	CS_2	76.13	115.3	10.588	3.036	3.867	4.834	6.014	7.387	9.185	11.215
Carbon tetrachloride	CCl_4	153.84	170.2	13.366	0.793	1.064	1.412	1.798	2.301	2 997	3.771
Chloroform	$CHCl_3$	119.39	142.7	12.488	1.528	1.934	2.475	3.191	4.061	5.163	6.342
Chloroprene	CH_2:$CC\ell$·CH:CH_2	88.54	138.9	8.046	1.760	2.320	2.901	3.655	4.563	5.685	6.981
Cyclohexane	C_6H_{12}	84.16	177.3	6.522	0.677	0.928	1.218	1.605	2.069	2.610	3.249
Cyclopentane	C_5H_{10}	70.13	120.7	6.248	2.514	3.287	4.177	5.240	6.517	8.063	9.668
1,1-Dichloroethane	CH_3CHCl_2	98.97	135.1	9.861	1.682	2.243	2.901	3.771	4.738	5.840	7.193
1,2-Dichloroethane	CH_2ClCH_2Cl	98.97	182.5	10.500	0.561	0.773	1.025	1.431	1.740	2.243	2.804
cis-1,2-Dichloroethylene	CHCl:CHCl	96.95	140.2	10.763	1.450	2.011	2.668	3.461	4.409	5.646	6.807
trans-1,2-Dichloro-ethylene	CHCl:CHCl	96.95	119.1	10.524	2.552	3.384	4.351	5.530	6.807	8.315	10.016
Diethylamine	$(C_2H_5)_2NH$	73.14	131.9	5.906	1.644	1.992	2.862	3.867	4.892	6.130	7.541
Diethyl ether	$C_2H_5OC_2H_5$	74.12	94.3	5.988	4.215	5.666	7.019	8.702	10.442	13.342	Boils
Di-*iso*-propyl ether	$(CH_3)_2CHOCH(CH_3)_2$	102.17	153.5	6.075	1.199	1.586	2.127	2.746	3.481	4.254	5.298
1,4-Dioxane	O·$CH_2CH_2OCH_2CH_2$	88.10	214.7	8.659	0.232	0.329	0.425	0.619	0.831	1.141	1.508
Dipropyl ether	$CH_3CH_2CH_2OCH_2CH_2CH_3$	102.17	195.8	6.260	0.425	0.619	0.831	1.102	1.431	1.876	2.320
Ethyl acetate	$C_2H_5OOCCH_3$	88.10	170.9	7.551	0.580	0.831	1.102	1.489	1.934	2.514	3.191
Ethyl acrylate	$C_2H_5OOCCH:CH_2$	100.11	211.8	7.750	0.213	0.290	0.425	0.599	0.831	1.122	1.470
Ethyl alcohol	C_2H_5OH	46.07	173.1	6.610	0.193	0.406	0.619	0.870	1.218	1.682	2 320
Freon 11	CC_3F	137.38	75.4	12.480	7.032	8.804	10.900	13.40	16.31	19.69	23.60

Appendix D

Procedures For Sampling Surface And Bulk Materials

This appendix presents procedures recommended for the collection of material samples from paved and unpaved roads and from bulk storage piles. (AP-42 Appendix E, "Procedures For Analyzing Surface And Bulk Materials Samples", presents analogous information for the analysis of the samples.) These recommended procedures are based on a review of American Society For Testing And Materials (ASTM) methods, such as C-136 (sieve analysis) and D-2216 (moisture content). The recommendations follow ASTM standards where practical, and where not, an effort has been made to develop procedures consistent with the intent of the pertinent ASTM standards.

This appendix emphasizes that, before starting any field sampling program, one must first define the study area of interest and then determine the number of samples that can be collected and analyzed within the constraints of time, labor, and money available. For example, the study area could be defined as an individual industrial plant with its network of paved/unpaved roadways and material piles. In that instance, it is advantageous to collect a separate sample for each major dust source in the plant. This level of resolution is useful in developing cost-effective emission reduction plans. On the other hand, if the area of interest is geographically large (say a city or county, with a network of public roads), collecting at least one sample from each source would be highly impractical. However, in such an area, it is important to obtain samples representative of different source types within the area.

D.1 Samples From Unpaved Roads

Objective

The overall objective in an unpaved road sampling program is to inventory the mass of particulate matter (PM) emissions from the roads. This is typically done by

1. Collecting "representative" samples of the loose surface material from the road,
2. Analyzing the samples to determine silt fractions, and,
3. Using the results in the predictive emission factor model given in AP-42 Section 11.2.1, Unpaved Roads, together with traffic data (e. g., number of vehicles traveling the road each day).

Before any field sampling program, it is necessary to define the study area of interest and to determine the number of unpaved road samples that can be collected and analyzed within the constraints of time, labor, and money available. For example, the study area could be defined as a very specific industrial plant having a network of roadways. Here it is advantageous to collect a separate sample for each major unpaved road in the plant. This level of resolution is useful in developing cost-effective emission reduction plans involving dust suppressants or traffic rerouting. On the other hand, the area of interest may be geographically large, and well-defined traffic information may not be easily obtained. In this case, resolution of the PM emission inventory to specific road

segments would not be feasible, and it would be more important to obtain representative road-type samples within the area by aggregating several sample increments.

Procedure

For a network consisting of many relatively short roads contained in a *well-defined study area* (as would be the case at an industrial plant), it is recommended that one collect a sample for each 0.8 kilometers (km) (0.5 miles [mi]) length, or portion thereof, for each major road segment. Here, the term "road segment" refers to the length of road between intersections (the nodes of the network) with other paved or unpaved roads. Thus, for a major segment 1 km (0.6 mi) long, two samples are recommended.

For longer roads in *study areas that are spatially diverse*, it is recommended that one collect a sample for each 4.8 km (3 mi) length of the road. Composite a sample from a minimum of three incremental samples. Collect the first sample increment at a random location within the first 0.8 km (0.5 mi), with additional increments taken from each remaining 0.8 km (0.5 mi) of the road, up to a maximum length of 4.8 km (3 mi). For a road less than 1.5 mi in length, an acceptable method for selecting sites for the increments is based on drawing three random numbers (x1, x2, x3) between zero and the length. Random numbers may be obtained from tabulations in statistical reference books, or scientific calculators may be used to generate pseudorandom numbers. See Figure D-1.

The following steps describe the collection method for samples (increments).

1. Ensure that the site offers an unobstructed view of traffic and that sampling personnel are visible to drivers. If the road is heavily traveled, use one person to "spot" and route traffic safely around another person collecting the surface sample (increment).

2. Using string or other suitable markers, mark a 0.3 meters (m) (1 foot [ft]) wide portion across the road. (WARNING: *Do not mark the collection area with a chalk line or in any other method likely to introduce fine material into the sample.*)

3. With a whisk broom and dustpan, remove the loose surface material from the hard road base. Do not abrade the base during sweeping. Sweeping should be performed slowly so that fine surface material is not injected into the air. NOTE: *Collect material only from the portion of the road over which the wheels and carriages routinely travel* (i. e., not from berms or any "mounds" along the road centerline).

4. Periodically deposit the swept material into a clean, labeled container of suitable size, such as a metal or plastic 19 liter (L) (5 gallon [gal]) bucket, having a sealable polyethylene liner. Increments may be mixed within this container.

5. Record the required information on the sample collection sheet (Figure D-2).

Sample Specifications

For uncontrolled unpaved road surfaces, a gross sample of 5 kilograms (kg) (10 pounds [lb]) to 23 kg (50 lb) is desired. Samples of this size will require splitting to a size amenable for analysis (see

Appendix E). For unpaved roads having been treated with chemical dust suppressants (such as petroleum resins, asphalt emulsions, etc.), the above goal may not be practical in well-defined study areas because a very large area would need to be swept. In general, a minimum of 400 grams (g) (1 lb) is required for silt and moisture analysis. Additional increments should be taken from heavily controlled unpaved surfaces, until the minimum sample mass has been achieved.

D.2 Samples From Paved Roads

Objective

The overall objective in a paved road sampling program is to inventory the mass of particulate emissions from the roads. This is typically done by

1. Collecting "representative" samples of the loose surface material from the road,
2. Analyzing the sample to determine the silt fraction, and,
3. Combining the results with traffic data in a predictive emission factor model.

The remarks above about definition of the study area and the appropriate level of resolution for sampling unpaved roads are equally applicable to paved roads. Before a field sampling program, it is necessary first to define the study area of interest and then to determine the number of paved road samples that can be collected and analyzed. For example, in a well-defined study area (e. g., an industrial plant), it is advantageous to collect a separate sample for each major paved road, because the resolution can be useful in developing cost-effective emission reduction plans. Similarly, in geographically large study areas, it may be more important to obtain samples representative of road types within the area by aggregating several sample increments.

Compared to unpaved road sampling, planning for a paved road sample collection exercise necessarily involves greater consideration as to types of equipment to be used. Specifically, provisions must be made to accommodate the characteristics of the vacuum cleaner chosen. For example, paved road samples are collected by cleaning the surface with a vacuum cleaner with "tared" (i. e., weighed before use) filter bags. Upright "stick broom" vacuums use relatively small, lightweight filter bags, while bags for industrial-type vacuums are bulky and heavy. Because the mass collected is usually several times greater than the bag tare weight, uprights are thus well suited for collecting samples from lightly loaded road surfaces. On the other hand, on heavily loaded roads, the larger industrial-type vacuum bags are easier to use and can be more readily used to aggregate incremental samples from all road surfaces. These features are discussed further below.

Procedure

For a network of many relatively short roads *contained in a well-defined study area* (as would be the case at an industrial plant), it is recommended that one collect a sample for each 0.8 km (0.5 mi) length, or portion thereof, for each major road segment. For a 1 km long (0.6 mi) segment, then, two samples are recommended. As mentioned, the term "road segment" refers to the length of road between intersections with other paved or unpaved roads (the nodes of the network).

For longer roads *in spatially heterogeneous study areas*, it is recommended that one collect a sample for each 4.8 km (3 mi) of sampled road length. Create a composite sample from a minimum of three incremental samples. Collect the first increment at a random location within the first 0.8 km (0.5 mi), with additional increments taken from each remaining 0.8 km (0.5 mi) of the road, up to a maximum length of 4.8 km (3 mi.) For a road less than 2.4 km (1.5 mi) long, an acceptable method for selecting sites for the increments is based on drawing three random numbers (x1, x2, x3) between zero and the length (See Figure D-3). Random numbers may be obtained from tabulations in statistical reference books, or scientific calculators may be used to generate pseudorandom numbers.

The following steps describe the collection method for samples (increments).

1. Ensure that the site offers an unobstructed view of traffic and that sampling personnel are visible to drivers. If the road is heavily traveled, use one crew member to "spot" and route traffic safely around another person collecting the surface sample (increment).

2. Using string or other suitable markers, mark the sampling portion across the road. (WARNING: *Do not mark the collection area with a chalk line or in any other method likely to introduce fine material into the sample.*) The widths may be varied between 0.3 m (1 ft) for visibly dirty roads and 3 m (10 ft) for clean roads. When an industrial-type vacuum is used to sample lightly loaded roads, a width greater than 3 m (10 ft) may be necessary to meet sample specifications, unless increments are being combined.

3. If large, loose material is present on the surface, it should be collected with a whisk broom and dustpan. NOTE: *Collect material only from the portion of the road over which the wheels and carriages routinely travel* (i. e., not from berms or any "mounds" along the road centerline). On roads with painted side markings, collect material "from white line to white line" (but avoid centerline mounds). Store the swept material in a clean, labeled container of suitable size, such as a metal or plastic 19 L (5 gal) bucket, with a sealable polyethylene liner. Increments for the same sample may be mixed within the container.

4. Vacuum the collection area using a portable vacuum cleaner fitted with an empty tared (preweighed) filter bag. NOTE: *Collect material only from the portion of the road over which the wheels and carriages routinely travel* (i. e., not from berms or any "mounds" along the road centerline). On roads with painted side markings, collect material "from white line to white line" (but avoid centerline mounds). The same filter bag may be used for different increments for one sample. For heavily loaded roads, more than one filter bag may be needed for a sample (increment).

5. Carefully remove the bag from the vacuum sweeper and check for tears or leaks. If necessary, reduce samples (using the procedure in Appendix E) from broom sweeping to a size amenable to analysis. Seal broom-swept material in a clean, labeled plastic jar for transport (alternatively, the swept material may be placed in the vacuum filter bag). Fold the unused portion of the filter bag, wrap a rubber band around the folded bag, and store the bag for transport.

6. Record the required information on the sample collection sheet (Figure D-4).

Sample Specifications

When broom swept samples are collected, they should be at least 400 g (1 lb) for silt and moisture analysis. Vacuum swept samples should be at least 200 g (0.5 lb). Also, the weight of an "exposed" filter bag should be at least 3 to 5 times greater than when empty. Additional increments should be taken until these sample mass goals have been attained.

D.3 Samples From Storage Piles

Objective

The overall objective of a storage pile sampling and analysis program is to inventory particulate matter emissions from the storage and handling of materials. This is done typically by

1. Collecting "representative" samples of the material,
2. Analyzing the samples to determine moisture and silt contents, and,
3. Combining analytical results with material throughput and meteorological information in an emission factor model.

As initial steps in storage pile sampling, it is necessary to decide (a) what emission mechanisms – material load-in to and load-out from the pile, wind erosion of the piles – are of interest and (b) how many samples can be collected and analyzed, given time and monetary constraints. (In general, annual average PM emissions from material handling can be expected to be much greater than those from wind erosion.) For an industrial plant, it is recommended that at least one sample be collected for each major type of material handled within the facility.

In a program to characterize load-in emissions, representative samples should be collected from material recently loaded into the pile. Similarly, representative samples for load-out emissions should be collected from areas that are worked by load-out equipment such as front end loaders or clamshells. For most "active" piles (i. e., those with frequent load-in and load-out operations), one sample may be considered representative of both loaded-in and loaded-out materials. Wind erosion material samples should be representative of the surfaces exposed to the wind.

In general, samples should consist of increments taken from all exposed areas of the pile (i. e., top, middle, and bottom). If the same material is stored in several piles, it is recommended that piles with at least 25% of the amount in storage be sampled. For large piles that are common in industrial settings (e. g., quarries, iron and steel plants), access to some portions may be impossible for the person collecting the sample. In that case, increments should be taken no higher than it is practical for a person to climb carrying a shovel and a pail.

Procedure

The following steps describe the method for collecting samples from storage piles.

1. Sketch plan and elevation views of the pile. Indicate if any portion is not accessible. Use the sketch to plan where the N increments will be taken by dividing the perimeter into N-1 roughly equivalent segments.

a. For a large pile, collect a minimum of 10 increments, as near to mid-height of the pile as practical.

b. For a small pile, a sample should be a minimum of 6increments, evenly distributed among the top, middle, and bottom.

"Small" or "large" piles, for practical purposes, may be defined as those piles which can or cannot, respectively, be scaled by a person carrying a shovel and pail.

2. Collect material with a straight-point shovel or a small garden spade, and store the increments in a clean, labeled container of suitable size (such as a metal or plastic 19 L [5 gal] bucket) with a sealable polyethylene liner. Depending upon the ultimate goals of the sampling program, choose one of the following procedures:

a. To characterize emissions from *material handling operations at an active pile*, take increments from the portions of the pile which most recently had material added and removed. Collect the material with a shovel to a depth of 10 to 15 centimeters (cm) (4 to 6 inches [in]). Do not deliberately avoid larger pieces of aggregate present on the surface.

b. To characterize *handling emissions from an inactive pile*, obtain increments of the core material from a 1 m (3 ft) depth in the pile. A sampling tube 2 m (6 ft) long, with a diameter at least 10 times the diameter of the largest particle being sampled, is recommended for these samples. Note that, for piles containing large particles, the diameter recommendation may be impractical.

c. If characterization of *wind erosion* , rather than material handling is the goal of the sampling program, collect the increments by skimming the surface in an upwards direction. The depth of the sample should be 2.5 cm (1 in), or the diameter of the largest particle, whichever is less. Do not deliberately avoid collecting larger pieces of aggregate present on the surface.

In most instances, collection method "a" should be selected.

3. Record the required information on the sample collection sheet (Figure D-5). Note the space for deviations from the summarized method.

Sample Specifications

For any of the procedures, the sample mass collected should be at least 5 kg (10 lb). When most materials are sampled with procedures 2.a or 2.b, ten increments will normally result in a sample of at least 23 kg (50 lb). Note that storage pile samples usually require splitting to a size more amenable to laboratory analysis.

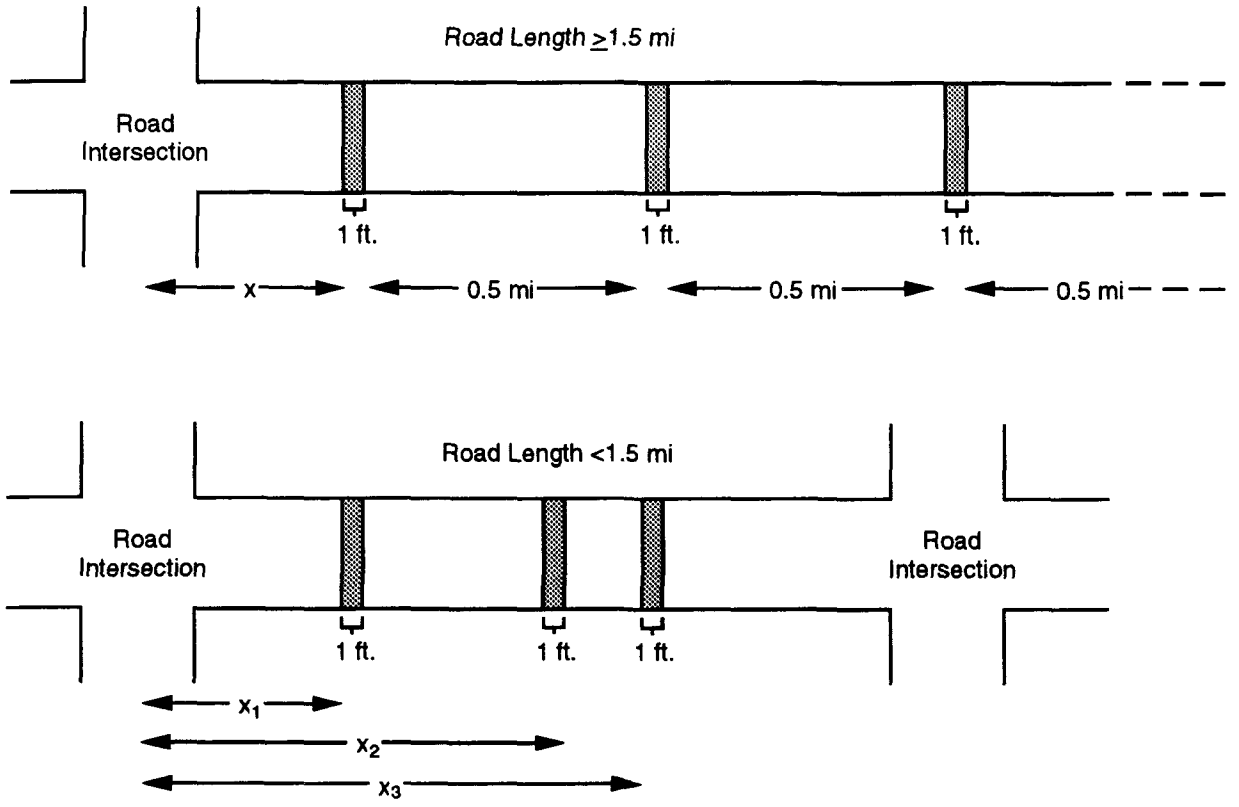


Figure D-1. Sampling locations for unpaved roads.

SAMPLING DATA FOR UNPAVED ROADS

Date Collected _____ Recorded by _____

Road Material (e.g., gravel, slag, dirt, etc.):* _____

_____

Site of sampling:

_____

METHOD:

1. Sampling device: whisk broom and dustpan
2. Sampling depth: loose surface material (do not abrade road base)
3. Sample container: bucket with sealable liner
4. Gross sample specifications:
   a. Uncontrolled surfaces -- 5 kg (10 lb) to 23 kg (50 lb)
   b. Controlled surfaces -- minimum of 400 g (1 lb) is required for analysis

Refer to AP-42 Appendix D for more detailed instructions.

Indicate any deviations from the above: _____

_____

_____

SAMPLING DATA COLLECTED:

Sample No.	Time	Location +	Surf. Area	Depth	Mass of Sample

* Indicate and give details if roads are controlled.

+ Use code given on plant or road map for segment identification. Indicate sampling location on map.

Figure D-2. Example data form for unpaved road samples.

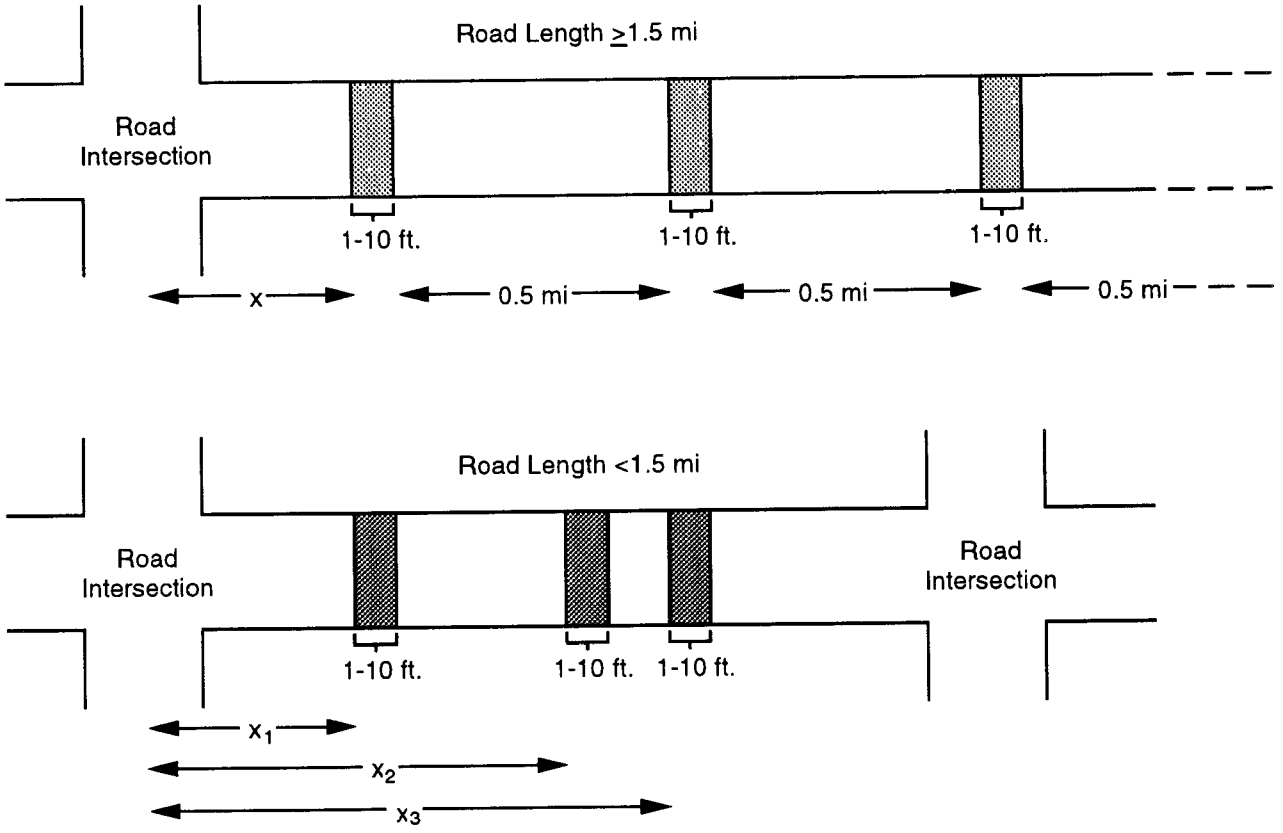


Figure D-3. Sampling locations for paved roads.

SAMPLING DATA FOR PAVED ROADS

Date Collected _____ Recorded by _____

Sampling location* _____ No. of Lanes _____

Surface type (e.g., asphalt, concrete, etc.)_____

Surface condition (e.g., good, rutted, etc.) _____

* Use code given on plant or road map for segment identification. Indication sampling location on map.

METHOD:

1. Sampling device: portable vacuum cleaner (whisk broom and dustpan if heavy loading present)
2. Sampling depth: loose surface material (do not sample curb areas or other untravelled portions of the road)
3. Sample container: tared and numbered vacuum cleaner bags (bucket with sealable liner if heavy loading present)
4. Gross sample specifications: Vacuum swept samples should be at least 200 g (0.5 lb), with the exposed filter bag weight should be at least 3 to 5 times greater than the empty bag tare weight.

Refer to AP-42 Appendix D for more detailed instructions.

Indicate any deviations from the above:_____
_____
_____

SAMPLING DATA COLLECTED:

Sample No.	Vacuum Bag ID	Vacuum Bag Tare Wgt (g)	Sampling Surface Dimensions (l x w)	Time	Mass of Broom-Swept Sample +

+ Enter "0" if no broom sweeping is performed.

Figure D-4. Example data form for paved roads.

SAMPLING DATA FOR STORAGE PILES

Date Collected _____ Recorded by _____

Type of material sampled _____

Sampling location* _____

METHOD:

1. Sampling device: pointed shovel (hollow sampling tube if inactive pile is to be sampled)
2. Sampling depth:
   For material handling of active piles: 10-15 cm (4-6 in)
   For material handling of inactive piles: 1 m (3 ft)
   For wind erosion samples: 2.5 cm (1 in) or depth of the largest particle (whichever is less)
3. Sample container: bucket with sealable liner
4. *Gross sample specifications:*
   For material handling of active or inactive piles: minimum of 6 increments with total sample weight of 5 kg (10 lb) [10 increments totalling 23 kg (50 lb) are recommended]
   For wind erosion samples: minimum of 6 increments with total sample weight of 5 kg (10 lb)

Refer to AP-42 Appendix D for more detailed instructions.

Indicate any deviations from the above:_____

_____

_____

SAMPLING DATA COLLECTED:

Sample No.	Time	Location* of Sample Collection	Device Used S/T **	Depth	Mass of Sample

* Use code given of plant or area map for pile/sample identification. Indicate each sampling location on map.

**Indicate whether shovel or tube.

Figure D-5. Example data form for storage piles.

Appendix E

Procedures For Analyzing Surface And Bulk Material Samples

This appendix discusses procedures recommended for the analysis of samples collected from paved and unpaved surfaces and from bulk storage piles. (AP-42 Appendix D, "Procedures For Sampling Surface And Bulk Materials", presents procedures for the collection of these samples.) These recommended procedures are based on a review of American Society For Testing And Materials (ASTM) methods, such as C-136 (sieve analysis) or D-2216 (moisture content). The recommendations follow ASTM standards where practical, and where not, an effort has been made to develop procedures consistent with the intent of the pertinent ASTM standards.

E.1 Sample Splitting

Objective

The collection procedures presented in Appendix D can result in samples that need to be reduced in size before laboratory analysis. Samples are often unwieldy, and field splitting is advisable before transporting the samples.

The size of the laboratory sample is important. Too small a sample will not be representative, and too much sample will be unnecessary as well as unwieldy. Ideally, one would like to analyze the entire gross sample in batches, but that is not practical. While all ASTM standards acknowledge this impracticality, they disagree on the exact optimum size, as indicated by the range of recommended samples, extending from 0.05 to 27 kilograms (kg) (0.1 to 60 pounds [lb]).

Splitting a sample may be necessary before a proper analysis. The principle in sizing a laboratory sample for silt analysis is to have sufficient coarse and fine portions both to be representative of the material and to allow sufficient mass on each sieve to assure accurate weighing. A laboratory sample of 400 to 1,600 grams (g) is recommended because of the capacity of normally available scales (1.6 to 2.6 kg). A larger sample than this may produce "screen blinding" for the 20 centimeter (cm) (8 inch [in]) diameter screens normally available for silt analysis. Screen blinding can also occur with small samples of finer texture. Finally, the sample mass should be such that it can be spread out in a reasonably sized drying pan to a depth of < 2.5cm (1 in).

Two methods are recommended for sample splitting: riffles, and coning and quartering. Both procedures are described below.

Procedures

Figure E-1 shows two riffles for sample division. Riffle slot widths should be at least three times the size of the largest aggregate in the material being divided. The following quote from ASTM Standard Method D2013-72 describes the use of the riffle.

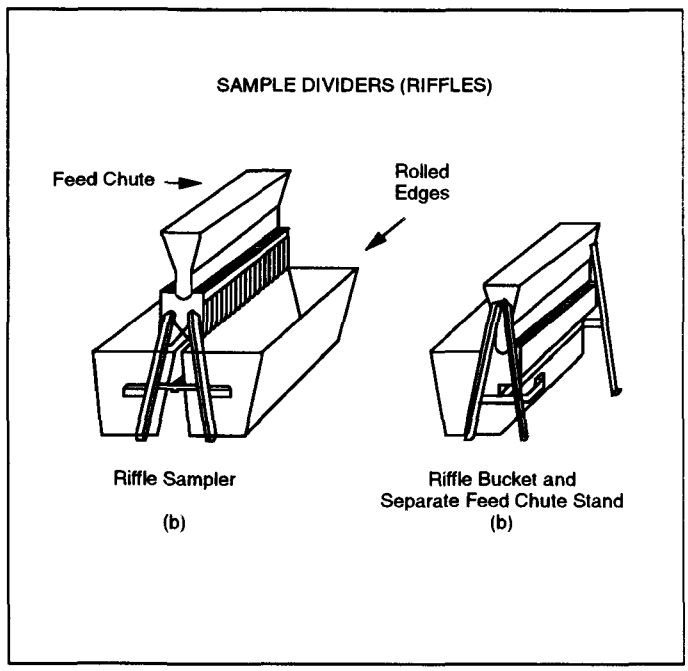


Figure E-1. Sample riffle dividers.

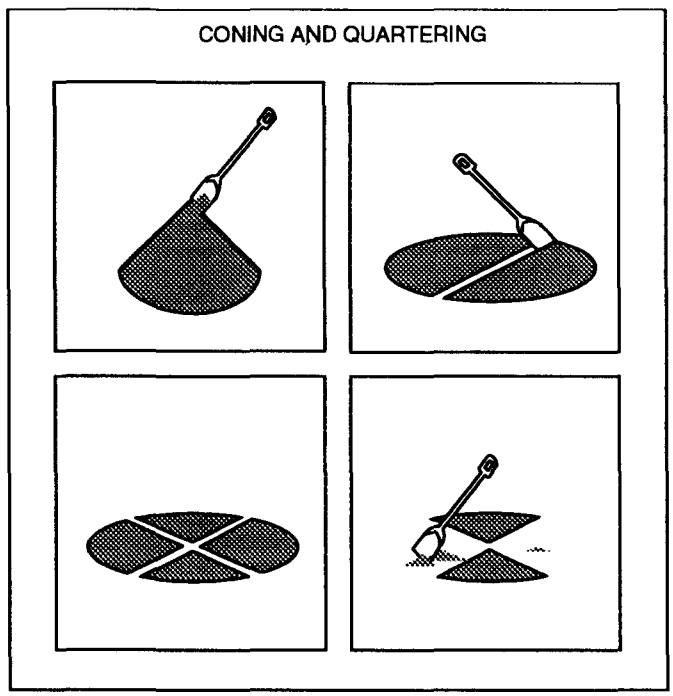


Figure E-2. Procedure for coning and quartering.

Divide the gross sample by using a riffle. Riffles properly used will reduce sample variability but cannot eliminate it. Riffles are shown in [Figure E-1]. Pass the material through the riffle from a feed scoop, feed bucket, or riffle pan having a lip or opening the full length of the riffle. When using any of the above containers to feed the riffle, spread the material evenly in the container, raise the container, and hold it with its front edge resting on top of the feed chute, then slowly tilt it so that the material flows in a uniform stream through the hopper straight down over the center of the riffle into all the slots, thence into the riffle pans, one-half of the sample being collected in a pan. Under no circumstances shovel the sample into the riffle, or dribble into the riffle from a small-mouthed container. Do not allow the material to build up in or above the riffle slots. If it does not flow freely through the slots, shake or vibrate the riffle to facilitate even flow.[1]

Coning and quartering is a simple procedure useful with all powdered materials and with sample sizes ranging from a few grams to several hundred pounds.[2] Oversized material, defined as > 0.6 millimeters (mm) (3/8 in) in diameter, should be removed before quartering and be weighed in a "tared" container (one for which its empty weight is known).

Preferably, perform the coning and quartering operation on a floor covered with clean 10 mil (mm) plastic. Take care that the material is not contaminated by anything on the floor or that any portion is not lost through cracks or holes. Samples likely affected by moisture or drying must be handled rapidly, preferably in a controlled atmosphere, and sealed in a container to prevent further changes during transportation and storage.

The procedure for coning and quartering is illustrated in Figure E-2. The following procedure should be used:

1. Mix the material and shovel it into a neat cone.

2. Flatten the cone by pressing the top without further mixing.

3. Divide the flat circular pile into equal quarters by cutting or scraping out two diameters at right angles.

4. Discard two opposite quarters.

5. Thoroughly mix the two remaining quarters, shovel them into a cone, and repeat the quartering and discarding procedures until the sample is reduced to 0.4 to 1.8 kg (1 to 4 lb).

E.2 Moisture Analysis

Paved road samples generally are not to be oven dried because vacuum filter bags are used to collect the samples. After a sample has been recovered by dissection of the bag, it is combined with any broom swept material for silt analysis. All other sample types are oven dried to determine moisture content before sieving.

Procedure

1. Heat the oven to approximately 110°C (230°F). Record oven temperature. (See Figure E-3.)

2. Record the make, capacity, and smallest division of the scale.

3. Weigh the empty laboratory sample containers which will be placed in the oven to determine their tare weight. Weigh any lidded containers with the lids. Record the tare weight(s). Check zero before each weighing.

4. Weigh the laboratory sample(s) in the container(s). For materials with high moisture content, assure that any standing moisture is included in the laboratory sample container. Record the combined weight(s). Check zero before each weighing.

5. Place sample in oven and dry overnight. Materials composed of hydrated minerals or organic material such as coal and certain soils should be dried for only 1.5 hours.

6. Remove sample container from oven and (a) weigh immediately if uncovered, being careful of the hot container; or (b) place a tight-fitting lid on the container and let it cool before weighing. Record the combined sample and container weight(s). Check zero before weighing.

7. Calculate the moisture, as the initial weight of the sample and container, minus the oven-dried weight of the sample and container, divided by the initial weight of the sample alone. Record the value.

8. Calculate the sample weight to be used in the silt analysis, as the oven-dried weight of the sample and container, minus the weight of the container. Record the value.

MOISTURE ANALYSIS

Date: _____ By: _____

Sample No: _____
Material: _____

Split Sample Balance: _____
Make _____
Capacity _____
Smallest division _____

Total Sample Weight: _____
(Excl. Container)
Number of Splits: _____

Split Sample Weight (before drying)
Pan + Sample: _____
Pan: _____
Wet Sample: _____

Oven Temperature: _____
Date In _____ Date Out _____
Time In _____ Time Out _____
Drying Time _____

Sample Weight (after drying)
Pan + Sample: _____
Pan: _____
Dry Sample: _____

MOISTURE CONTENT:
(A) Wet Sample Wt. _____
(B) Dry Sample Wt. _____
(C) Difference Wt. _____

$$\frac{C \times 100}{A} = _____ \%\ \text{Moisture}$$

Figure E-3. Example moisture analysis form.

E.3 Silt Analysis

Objective

Several open dust emission factors have been found to be correlated with the silt content (< 200 mesh) of the material being disturbed. The basic procedure for silt content determination is mechanical, dry sieving. For sources other than paved roads, the same sample which was oven-dried to determine moisture content is then mechanically sieved.

For paved road samples, the broom-swept particles and the vacuum-swept dust are individually weighed on a beam balance. The broom-swept particles are weighed in a container, and the vacuum-swept dust is weighed in the bag of the vacuum, which was tared before sample collection. After weighing the sample to calculate total surface dust loading on the traveled lanes, combine the broom-swept particles and the vacuumed dust. Such a composite sample is usually small and may not require splitting in preparation for sieving.

Procedure

1. Select the appropriate 20-cm (8-in) diameter, 5-cm (2-in) deep sieve sizes. Recommended U. S. Standard Series sizes are 3/8 in, No. 4, No. 40, No. 100, No. 140, No. 200, and a pan. Comparable Tyler Series sizes can also be used. The No. 20 and the No. 200 are mandatory. The others can be varied if the recommended sieves are not available, or if buildup on one particulate sieve during sieving indicates that an intermediate sieve should be inserted.

2. Obtain a mechanical sieving device, such as a vibratory shaker or a Roto-Tap® without the tapping function.

3. Clean the sieves with compressed air and/or a soft brush. Any material lodged in the sieve openings or adhering to the sides of the sieve should be removed, without handling the screen roughly, if possible.

4. Obtain a scale (capacity of at least 1600 grams [g] or 3.5 lb) and record make, capacity, smallest division, date of last calibration, and accuracy. (See Figure E-4.)

5. Weigh the sieves and pan to determine tare weights. Check the zero before every weighing. Record the weights.

6. After nesting the sieves in decreasing order of size, and with pan at the bottom, dump dried laboratory sample (preferably immediately after moisture analysis) into the top sieve. The sample should weigh between ~ 400 and 1600 g (~ 0.9 and 3.5 lb). This amount will vary for finely textured materials, and 100 to 300 g may be sufficient when 90% of the sample passes a No. 8 (2.36 mm) sieve. Brush any fine material adhering to the sides of the container into the top sieve and cover the top sieve with a special lid normally purchased with the pan.

7. Place nested sieves into the mechanical sieving device and sieve for 10 minutes (min.). Remove pan containing minus No. 200 and weigh. Repeat the sieving at 10-min. intervals until the

difference between two successive pan sample weighings (with the pan tare weight subtracted) is less than 3.0%. Do not sieve longer than 40 min.

8. Weigh each sieve and its contents and record the weight. Check the zero before every weighing.

9. Collect the laboratory sample. Place the sample in a separate container if further analysis is expected.

10. Calculate the percent of mass less than the 200 mesh screen (75 micrometers [μm]). This is the silt content.

E.4 References

1. "Standard Method Of Preparing Coal Samples For Analysis", *Annual Book Of ASTM Standards, 1977*, D2013-72, American Society For Testing And Materials, Philadelphia, PA, 1977.

2. L. Silverman, *et al.*, *Particle Size Analysis In Industrial Hygiene*, Academic Press, New York, 1971.

SILT ANALYSIS

Date _____
Sample No: _____
Material: _____

Split Sample Balance:
Make _____

Smallest Division _____

By _____
Sample Weight (after drying)
Pan + Sample: _____
Pan: _____
Dry Sample: _____
Capacity _____
Final Weight: _____

$$\% \text{ Silt} = \frac{\text{Net Weight <200 Mesh}}{\text{Total Net Weight}} \times 100 = ___\%$$

SIEVING

Time: Start:	Weight (Pan Only)
Initial (Tare):	
10 min:	
20 min:	
30 min:	
40 min:	

Screen	Tare Weight (Screen)	Final Weight (Screen + Sample)	Net Weight (Sample)	%
3/8 in.				
4 mesh				
10 mesh				
20 mesh				
40 mesh				
100 mesh				
140 mesh				
200 mesh				
Pan				

Figure E-4. Example silt analysis form.

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO
AP-42	Volume I, Supplement F	

4. TITLE AND SUBTITLE	5. REPORT DATE
Supplement F To Compilation Of Air Pollutant Emission Factors, Volume I	July 1993
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO
9. PERFORMING ORGANIZATION NAME AND ADDRESS U. S. Environmental Protection Agency Office Of Air Quality Planning And Standards (MD 14) Research Triangle Park, NC 27711	10. PROGRAM ELEMENT NO.
	11. CONTRACT/GRANT NO.
12. SPONSORING AGENCY NAME AND ADDRESS	13. TYPE OF REPORT AND PERIOD COVERED
	14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

16. ABSTRACT

This supplement to the AP-42 series contains new or revised emission information on Bituminous And Subbituminous Coal Combustion; Anthracite Coal Combustion; Fuel Oil Combustion; Natural Gas Combustion; Liquefied Petroleum Gas Combustion; Wood Waste Combustion In Boilers; Lignite Combustion; Bagasse Combustion In Sugar Mills; Residential Fireplaces; Residential Wood Stoves; Waste Oil Combustion; Refuse Combustion; Sewage Sludge Incineration; Medical Waste Incineration; Landfills; Stationary Gas Turbines For Electricity Generation; Heavy Duty Natural Gas Fired Pipeline Compressor Engines; Gasoline And Diesel Industrial Engines; Large Stationary Diesel And All Stationary Dual Fuel Engines; Synthetic Ammonia; Chlor-Alkali; Hydrochloric Acid; Hydrofluoric Acid; Nitric Acid; Phosphoric Acid; Soap And Detergents; Sodium Carbonate; Sulfuric Acid; Sulfur Recovery; Ammonium Nitrate; Normal Superphosphates; Triple Superphosphates; Ammonium Phosphate; Urea; Ammonium Sulfate; Zinc Smelting; Secondary Zinc Processing; Lead Oxide And Pigment Production; Clay And Fly Ash Sintering; Concrete Batching; Glass Fiber Manufacturing; Gypsum Processing; Mineral Wool Processing; Perlite Processing; Phosphate Rock Processing; Metallic Minerals Processing; Lightweight Aggregate Manufacturing; Feldspar Processing; Storage Of Organic Liquids; Procedures For Sampling Surface And Bulk Materials; and Procedures For Analyzing Surface And Bulk Material Samples.

This information is necessary for developing State Implementation Plans, emission inventories and operating permits.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Stationary Sources Point Sources Area Sources Emissions Emission Factors Air Pollutants		

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS *(This Report)*	21. NO. OF PAGES
		628
	20. SECURITY CLASS *(This page)*	22. PRICE

EPA Form 2220-1 (Rev. 4-77) PREVIOUS EDITION IS OBSOLETE

*U.S. G.P.O.:1993-728-090:87002