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EPA

LOCATING AND ESTIMATING AIR EMISSIONS FROM SOURCES OF MERCURY AND MERCURY COMPOUNDS



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**LOCATING AND ESTIMATING AIR EMISSIONS
FROM SOURCES OF MERCURY AND
MERCURY COMPOUNDS**

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U. S. ENVIRONMENTAL PROTECTION AGENCY

Office Of Air and Radiation

Office Of Air Quality Planning And Standards

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EXECUTIVE SUMMARY

The emissions of mercury and mercury compounds into the atmosphere are of special significance because of the Clean Air Act Amendments of 1990. These amendments mandate that mercury emissions be subject to standards that allow for the maximum degree of reduction of emissions and that, by 1995, a list of source categories must be established that account for no less than 90 percent of mercury emissions. This document is designed to assist groups interested in inventorying air emissions of mercury by providing a compilation of available information on sources and emissions of these substances.

In the U.S., mercury is produced primarily as a byproduct of gold mining and as a result of secondary production; the last mercury mine was closed in 1990. In 1991, the total U.S. supply of mercury was 1,416 Mg (1,558 tons), of which approximately 4 percent resulted from imports. The demand for mercury in the U.S. has decreased sharply since 1989. In 1991, the U.S. demand was only 473 Mg (520 tons) or 33 percent of the supply. This represents a demand that is only 39 percent of the 1989 demand. The majority of the 1991 supply was for exports, which accounted for 56 percent of the supply; the remaining 11 percent was used to replenish industry stocks.

In 1991, 10 source categories accounted for the U.S. demand for mercury; the chlor-alkali industry was the major user. Other major users of mercury were for battery production and production of measurement and control instruments. These three source categories accounted for 70 percent of the total U.S. demand for

mercury; the other seven source categories accounted for the remaining 30 percent.

Nationwide mercury emissions were estimated for several source categories for 1990. This was the latest year for which adequate information was available for all source categories and it was not desirable to mix the specific source emission estimates for 1990 and 1991. The total 1990 nationwide mercury emissions estimate was 302 Mg (332 tons) from five major source categories. Table ES-1 shows the estimated nationwide emissions by major source category and the percent contribution of each category to the total emissions. The five specific sources emitting the largest quantities of mercury were coal combustion, municipal waste combustion, medical waste combustion, oil combustion, and paint application.

TABLE ES-1. ESTIMATED NATIONWIDE EMISSIONS

Major source category	Estimated nationwide emissions, Mg (tons)	Percent of total emissions
Mercury and mercury compound production	5.7 (6.3)	1.9
Major uses of mercury	18.4 (20.2)	6.1
Combustion sources	243 (267.5)	80.5
Miscellaneous manufacturing processes	15.9 (17.5)	5.3
Other miscellaneous sources	18.6 (20.6)	6.2
TOTAL	302 (332)	100

SECTION 1
PURPOSE OF DOCUMENT

The U. S. Environmental Protection Agency (EPA), State, and local air pollution control agencies are becoming increasingly aware of the presence of substances in the ambient air that may be toxic at certain concentrations. This awareness, in turn, has led to attempts to identify source/receptor relationships for these substances and to develop control programs to regulate emissions. Unfortunately, little information exists on the ambient air concentration of these substances or about the sources that may be discharging them to the atmosphere.

To assist groups interested in inventorying air emissions of various potentially toxic substances, EPA is preparing a series of documents such as this that compiles available information on sources and emissions of these substances. Prior documents in the series are listed below:

<u>Substance</u>	<u>EPA Publication Number</u>
Acrylonitrile	EPA-450/4-84-007a
Carbon Tetrachloride	EPA-450/4-84-007b
Chloroform	EPA-450/4-84-007c
Ethylene Dichloride	EPA-450/4-84-007d
Formaldehyde	EPA-450/4-91-012
Nickel	EPA-450/4-84-007f
Chromium	EPA-450/4-84-007g
Manganese	EPA-450/4-84-007h
Phosgene	EPA-450/4-84-007i
Epichlorohydrin	EPA-450/4-84-007j
Vinylidene Chloride	EPA-450/4-84-007k
Ethylene Oxide	EPA-450/4-84-007l
Chlorobenzene	EPA-450/4-84-007m

Polychlorinated Biphenyls (PCB's)	EPA-450/4-84-007n
Polycyclic Organic Matter (POM)	EPA-450/4-84-007p
Benzene	EPA-450/4-84-007q
Perchloroethylene and Trichloroethylene	EPA-450/2-89-013
Municipal Waste Combustion	EPA-450/2-89-006
Coal and Oil Combustion	EPA-450/2-89-001
1,3-Butadiene	EPA-450/2-89-021
Chromium (Supplement)	EPA-450/2-89-002
Sewage Sludge	EPA-450/2-90-009
Styrene	EPA-454/R-93-011
Cadmium	Number to be Assigned
Methylene Chloride	EPA-454/R-93/006
Medical Waste	Number to be Assigned
TCDD/TCDF	Number to be Assigned
Toluene	Number to be Assigned
Xylenes	Number to be Assigned
Methyl Ethyl Ketone	Number to be Assigned
Methyl Chloroform	Number to be Assigned
Chlorobenzene (Update)	Number to be Assigned
Chloroform (Update)	Number to be Assigned

This document deals specifically with mercury and mercury compounds; however, the majority of the information contained in this document concerns mercury.

In addition to the information presented in this document, another potential source of emissions data for mercury and mercury compounds is the Toxic Chemical Release Inventory (TRI) form required by Section 313 of Title III of the 1986 Superfund Amendments and Reauthorization Act (SARA 313).¹ SARA 313 requires owners and operators of facilities in certain Standard Industrial Classification Codes that manufacture, import, process or otherwise use toxic chemicals (as listed in Section 313) to report annually their releases of these chemicals to all environmental media. As part of SARA 313, EPA provides public access to the annual emissions data. The TRI data include general facility information, chemical information, and emissions data. Air emissions data are reported as total facility release estimates for fugitive emissions and point source emissions. No

individual process or stack data are provided to EPA under the program. The TRI requires sources to use stack monitoring data for reporting, if available, but the rule does not require stack monitoring or other measurement of emissions if data from these activities are unavailable. If monitoring data are unavailable, emissions are to be quantified based on best estimates of releases to the environment.

The reader is cautioned that the TRI will not likely provide facility, emissions, and chemical release data sufficient for conducting detailed exposure modeling and risk assessment studies. In many cases, the TRI data are based on annual estimates of emissions (i.e., on emission factors, material balance calculations, and engineering judgment). We recommend the use of TRI data in conjunction with the information provided in this document to locate potential emitters of mercury and to make preliminary estimates of air emissions from these facilities.

Mercury is of particular importance as a result of the Clean Air Act Amendments of 1990. Mercury and its compounds are included in the Title III list of hazardous air pollutants and will be subject to standards established under Section 112, including maximum achievable control technology (MACT). Also, Section 112(c)(6) of the 1990 Amendments mandate that mercury (among others) be subject to standards that allow for the maximum degree of reduction of emissions. These standards are to be promulgated no later than 10 years following the date of enactment. Additionally, within 5 years of the date of enactment, a list of source categories that account for no less than 90 percent of mercury emissions must be established.

The data on mercury emissions are based, whenever possible, on the results of actual test procedures. Data presented in this document are total mercury emissions and do not differentiate the chemical forms of the mercury. The sampling and analysis

procedures employed for the determination of the mercury concentrations from various sources are presented in Section 9, Source Test Method. These methods do not provide data on the speciation of the mercury in the emissions.

SECTION 2

OVERVIEW OF DOCUMENT CONTENTS

As noted in Section 1, the purpose of this document is to assist Federal, State, and local air pollution agencies and others who are interested in locating potential air emitters of mercury and mercury compounds and estimating air emissions from these sources. Because of the limited background data available, the information summarized in this document does not and should not be assumed to represent the source configuration or emissions associated with any particular facility.

This section provides an overview of the contents of this document. It briefly outlines the nature, extent, and format of the material presented in the remaining sections of this document.

Section 3 of this document provides a brief summary of the physical and chemical characteristics of mercury and mercury compounds and an overview of their production and uses. A chemical use tree summarizes the quantities of mercury produced by various techniques as well as the relative amounts consumed by various end uses. This background section may be useful to someone who wants to develop a general perspective on the nature of the substance and where it is manufactured and consumed.

Sections 4 to 7 of this document focus on the major industrial source categories that may discharge mercury-containing air emissions. Section 4 discusses the production of mercury and mercury compounds. Section 5 discusses the different uses of mercury as an industrial feedstock. Section 6 discusses emissions from combustion sources. Section 7 discusses emissions

from miscellaneous manufacturing processes, and Section 8 discusses emissions from miscellaneous fugitive and area sources. For each major industrial source category described, process descriptions and flow diagrams are given wherever possible, potential emission points are identified, and available emission factor estimates are presented that show the potential for mercury emissions before and after controls are employed by industry. Individual companies are named that are reported to be involved with the production and/or use of mercury based on industry contacts, the Toxic Release Inventory (TRI), and available trade publications.

Section 9 of this document summarizes available procedures for source sampling and analysis of mercury. Details are not provided nor is any EPA endorsement given or implied for any of these sampling and analysis procedures. Section 10 provides references. Appendix A presents calculations used to derive the estimated 1990 nationwide mercury emissions. Appendix B presents a summary of the combustion source test data. Appendix C lists U.S. Portland cement manufacturers. Appendix D presents U.S. crude oil distillation capacity.

This document does not contain any discussion of health or other environmental effects of mercury, nor does it include any discussion of ambient air levels or ambient air monitoring techniques.

Comments on the content or usefulness of this document are welcome, as is any information on process descriptions, operating practices, control measures, and emissions that would enable EPA to improve its contents. All comments should be sent to:

Chief, Emission Factor and Methodology Section (MD-14)
Emission Inventory Branch
U. S. Environmental Protection Agency
Research Triangle Park, NC 27711

SECTION 3

BACKGROUND

3.1 NATURE OF THE POLLUTANT

Mercury, also called quicksilver, is a heavy, silver-white metal that exists as a liquid at ambient temperatures. Its symbol, Hg, comes from the Latin word, hydrargyrum, meaning liquid silver. Mercury and its major ore, cinnabar (HgS), have been known and used for thousands of years. Table 3-1 summarizes the major chemical and physical properties of mercury.

Mercury is stable at ambient temperatures. It does not react with air, ammonia, carbon dioxide, nitrous oxide, or oxygen but readily combines with the halogens and sulfur. Mercury will react with any hydrogen sulfide present in the air and should be kept in covered containers.² It is not affected to any extent by hydrochloric acid but is attacked by concentrated sulfuric acid. Mercury can be dissolved in either dilute or concentrated nitric acid, resulting in the formation of either mercurous [Hg(I)] salts (if the mercury is in excess or no heat is applied), or mercuric [Hg(II)] salts (if excess acid or heat is used).

Elemental (metallic) mercury is used primarily in electrical applications, including batteries, electrical lamps, and wiring and switching devices. Its low electrical resistivity makes it one of the best electrical conductors among the metals.²

In the ionic form, mercury exists in one of two oxidation states (or valences): Hg(I) or the mercurous ion and Hg(II) or the mercuric ion. Of the two states, the higher oxidation state, Hg(II), is the more stable. Mercury compounds having technical and commercial importance include mercuric sulfide, mercuric

TABLE 3-1. PHYSICAL AND CHEMICAL PROPERTIES OF MERCURY

Property	Value
Atomic weight	200.59
Crystal system	Rhombohedral
CAS registry number	7439-97-6
Atomic number	80
Valences	1, 2
Outer electron configuration	5d ¹⁰ 6s ²
Metallic radius, Å	1.10 (Hg ²⁺) 1.50 (Hg ⁺)
Covalent radius, Å	1.440
Electrode reduction potentials, normal, V	
$\text{Hg}^{2+} + 2\text{e} \rightleftharpoons \text{Hg}$	0.851
$\text{Hg}_2^{2+} + 2\text{e} \rightleftharpoons 2\text{Hg}$	0.7961
$2\text{Hg}^{2+} + 2\text{e} \rightleftharpoons \text{Hg}_2^{2+}$	0.905
Melting point, °C	-38.87
Boiling point, °C	356.9
Latent heat of fusion, J/g (cal/g)	11.80 (2.8)
Latent heat of vaporization, J/g (cal/g)	271.96 (65.0)
Specific heat, J/g (cal/g)	
Solid	1.1335 (0.271)
-75.6°C	0.141 (0.0337)
-40°C	0.0231 (0.00552)
-263.3°C	
Liquid	
-36.7°C	0.1418 (0.0339)
210°C	1.1335 (0.271)
Electrical resistivity, Ω-cm, at 20°C	95.8 × 10 ⁻⁶
Density, g/cm ³	
at 20°C	13.546
at melting point	14.43
at -38.8°C (solid)	14.193
at 0°C	13.595
Thermal conductivity, w/(cm ² · K)	0.092
Vapor pressure, 25°C	2 × 10 ⁻³ mm Hg
Solubility in water, 25°C	0.28 μmol/L

Source: References 2 and 3.

oxide, mercuric chloride, mercuric and mercurous sulfate, mercurous nitrate, and various organic mercury salts (e.g., phenylmercuric acetate).

Metallic mercury can be found in small quantities in some ore deposits; however, it usually occurs as a sulfide. It occurs sometimes as the chloride or the oxide, typically in conjunction with base and precious metals. Although cinnabar (HgS) is by far the predominant mercury mineral in ore deposits, other common mercury-containing minerals include corderoite ($\text{Hg}_3\text{S}_2\text{Cl}_2$), livingstonite (HgSb_4S_7), montroydite (HgO), terlinguaite (Hg_2OCl), calomel (HgCl), and metacinnabar, a black form of cinnabar.²

Mercury has a tendency to form alloys or amalgams with almost all metals except iron, although at higher temperatures it will even form alloys with iron. Mercury forms amalgams with vanadium, iron, niobium, molybdenum, cesium, tantalum, or tungsten to produce metals with good to excellent corrosion resistance.² A mercury-silver amalgam has been traditionally used for teeth fillings.

3.2 OVERVIEW OF PRODUCTION, USE, AND EMISSIONS

3.2.1 Production

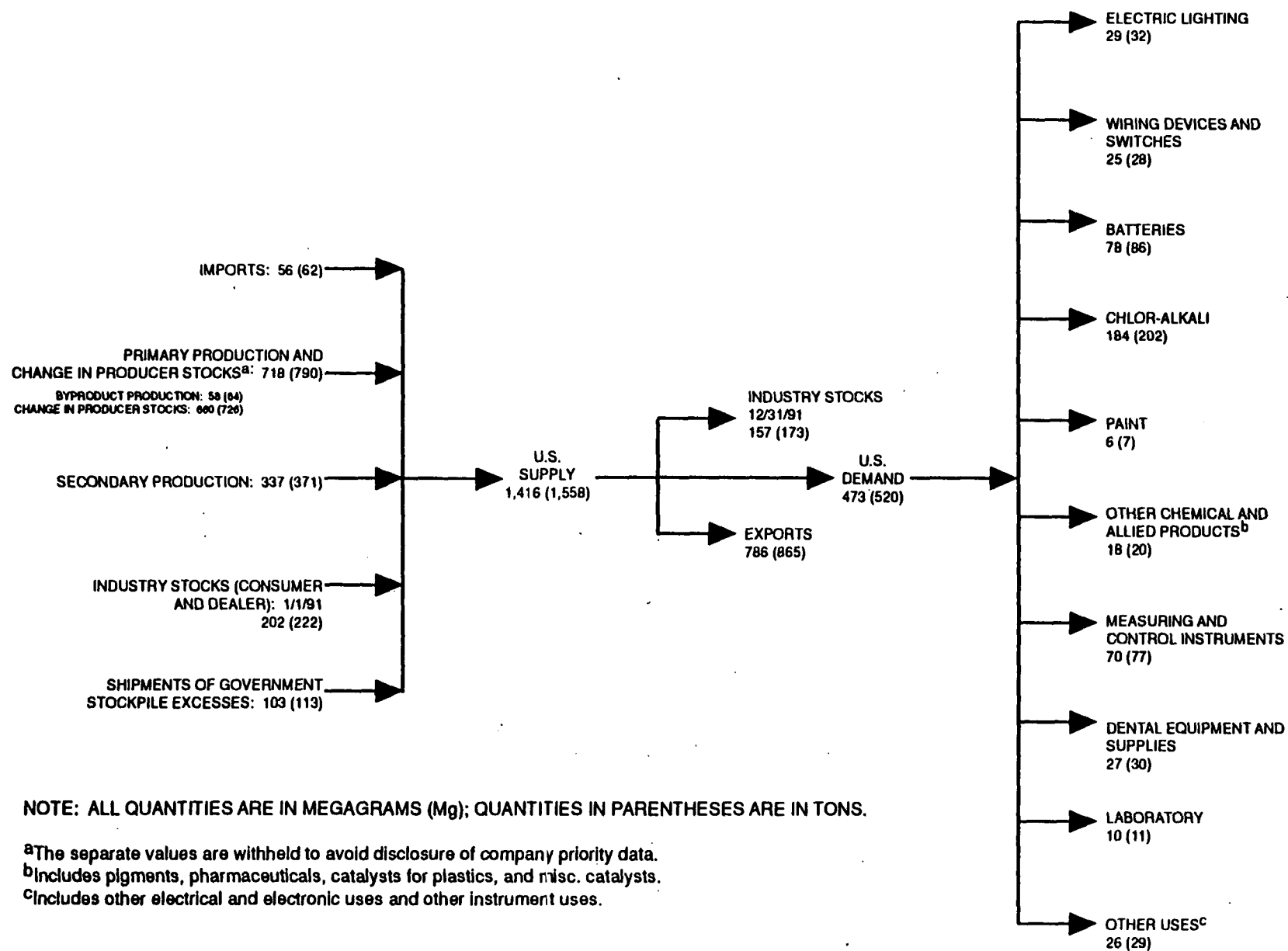
Primary production of mercury occurs principally as a byproduct of gold mining. Mercury was previously mined from mercury ores in Nevada, but that mine closed in 1990. It is still produced in relatively small quantities as a byproduct from gold ores in Nevada, California, and Utah.⁴

Secondary production (recycling) of mercury includes the processing of scrapped mercury-containing products, industrial waste and scrap, and scrap mercury from Government stocks.⁴ Major sources of recycled mercury are dental amalgams and scrap

mercury from instrument and electrical manufacturers, wastes and sludges from research laboratories and electrolytic refining plants, and mercury batteries.²

Figure 3-1 presents the 1991 supply-and-demand diagram for mercury. The information contained in Figure 3-1 was obtained from the U.S. Bureau of Mines, Division of Mineral Commodities. As shown in Figure 3-1, the total 1991 U.S. supply of mercury was 1,416 Mg (1,558 tons). An estimated 75 percent of the total supply resulted from the primary and secondary mercury production processes. The large percentage of the total supply due to primary and secondary production processes is presumed to be attributed to the sale of mercury stockpiles from the McDermitt Mine in Nevada which ceased operation in 1990. Figure 3-1 also shows that of the total 1991 U.S. mercury supply, 33 percent (473 Mg/520 tons) was used to meet domestic demands, while 56 percent met export demands and 11 percent supplied industry stocks.

The 1991 supply-demand figures shown in Figure 3-1 present a dramatic change in the overall structure of the industrial demand for mercury in the U.S. A brief review of figures for 1989, 1990, and 1991 reveal the magnitude of the changes that have occurred.⁴ In 1989, the U.S. industrial demand for mercury was 1,214 Mg (1,335 tons); in 1990, it was 720 Mg (792 tons); and in 1991, it was 473 Mg (520 tons). Conversely, exports of mercury in 1989 were 221 Mg (243 tons); in 1990, exports were 311 Mg (342 tons); and in 1991, exports reached 786 Mg (865 tons). Since 1989, U.S. industrial demand has decreased by 61 percent (741 Mg/815 tons) and exports have increased by 356 percent (565 Mg/622 tons). The impacts of these changes can be seen in the changes in the end uses of mercury.

Figure 3-1. 1991 supply and demand of mercury.⁴

3.2.2 End-Use

Because of its unique qualities and properties, mercury has various end-uses. Figure 3-1 outlines the 1991 final end-use pattern for mercury to be:

1. Electric lighting;
2. Wiring devices and switches;
3. Batteries;
4. Chlor-alkali production;
5. Paint manufacture;
6. Chemical and allied products production;
7. Measuring and control equipment;
8. Dental equipment and supplies;
9. Laboratory uses; and
10. Other miscellaneous uses.

The percentage of the total 1991 mercury supply that was consumed by each end-use category is shown in Figure 3-2. Chlor-alkali production, at 38.9 percent, accounts for the largest percentage consumption of mercury. Battery manufacture and measuring and control instruments manufacture represent the second and third largest consumers of mercury at 16.5 percent and 14.8 percent, respectively. The remaining source categories, as outlined in Figure 3-1, account for approximately 30 percent of total mercury consumption in 1991.

During 1989-1991, the demand picture for mercury underwent a significant change in the overall demand among industries.⁴ The magnitude of these overall changes and the dramatic change in mercury demand for specific industries is shown in Table 3-2 for the mercury-using industries. These are the same segments shown in Figures 3-1 and 3-2.

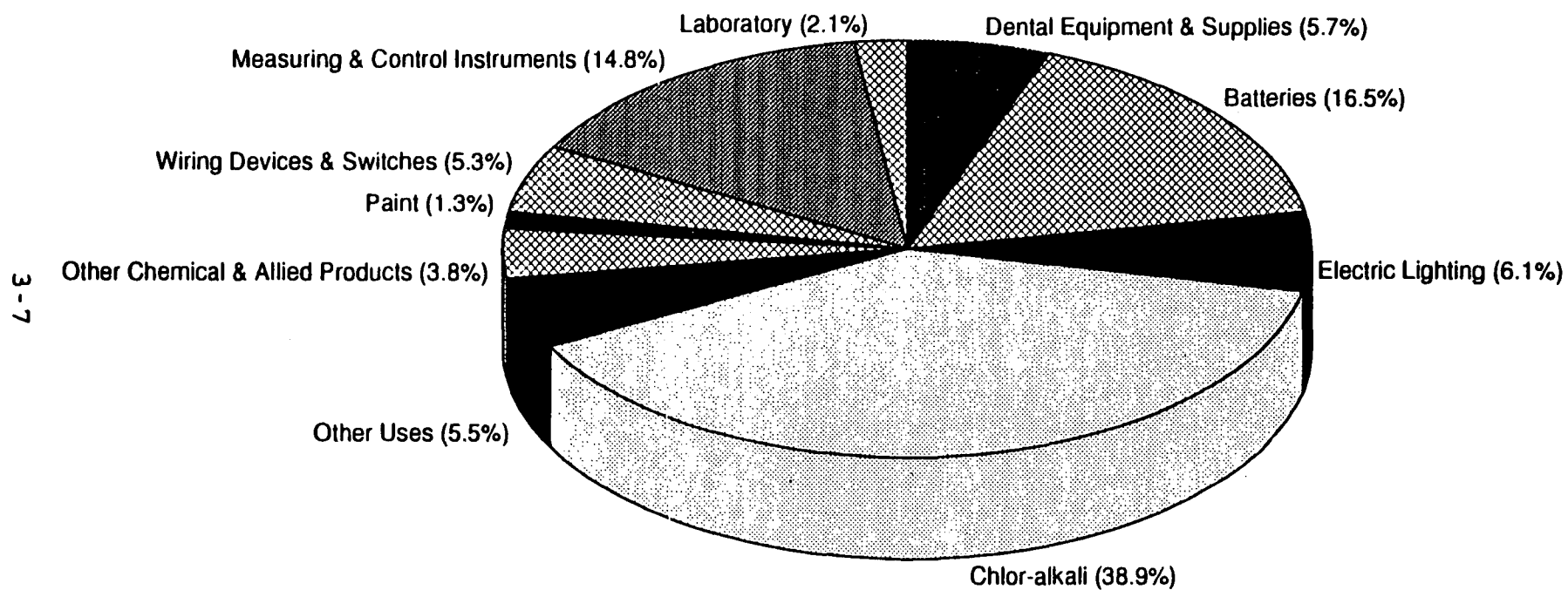


Figure 3-2. End-use pattern of mercury.⁴

TABLE 3-2. COMPARISON OF MERCURY DEMAND BY
USER INDUSTRY IN 1989 AND 1991

Industry	Mercury demand, Mg (tons)	
	1989	1991
Electric lighting	31 (34)	29 (32)
Wiring devices/ switches	141 (155)	25 (28)
Batteries	250 (275)	78 (86)
Chlor-alkali	381 (419)	184 (202)
Paint	192 (211)	6 (7)
Other chemical and allied products	40 (44)	18 (20)
Measuring and control instruments	87 (96)	70 (77)
Dental equipment/supplies	39 (43)	27 (30)
Laboratory	18 (20)	10 (11)
Other uses	35 (39)	26 (29)
Total demand	1,214 (1,335)	473 (520)

Note: Columns may not add due to rounding

Source: Reference 4.

The most dramatic change occurred in the paint industry where demand dropped to only 6 Mg (7 tons) compared to 192 Mg (211 tons) in 1989. Other industries showing significant decreases in demand were wiring devices and switches, batteries, chlor-alkali, and, to a lesser extent, other chemicals and allied products.

The demand decreases in end-use areas will definitely affect the magnitude of mercury emissions in the U.S. and will lead to secondary impacts. One secondary major impact on emissions will be in the area of waste disposal, particularly in municipal and medical waste combustion. In medical waste, used batteries and used laboratory equipment constitute a major source of mercury and mercury emissions during incineration. The mercury demand

for laboratory uses decreased by 50 percent but was at a relatively low level at the start (18 Mg/20 tons). Mercury use in batteries showed a major decrease in quantity (172 Mg/189 tons), and this decrease should be evident in mercury emissions from both medical waste and municipal waste incineration. In addition, the significant decrease in demand for the wiring devices and switches industry may also be felt in emissions from municipal waste incinerations. This impact would occur further in the future than the impact from batteries because of the longer equipment lifetime.

3.2.3 Emissions

The source of emissions information used to determine a portion of the source categories is the 1990 Toxic Chemicals Release Inventory System (TRI) form required by Section 313 of Title III of the 1986 Superfund Amendments and Reauthorization Act (SARA 313).⁵ This section requires owners and operators of facilities in Standard Industrial Classification (SIC) codes 20-39 that manufacture, import, process, or otherwise use toxic chemicals to report their annual air releases of these chemicals. The emissions are to be based on source tests (if available); otherwise, emissions may be based on emission factors, mass balances, or other approaches. Certain source categories (i.e., combustion sources) that account for substantial mercury emissions, but which are not represented in TRI, were included in the estimates presented.

It should be noted that, in selected cases, facilities reported to TRI under multiple SIC codes. As a result, it was difficult to assign emissions to a specific SIC code. In this case, efforts were made to determine the appropriate SIC codes associated with the emissions. However, if that was not possible, the data were not used in the analysis. Other

reference sources provided additional potential emission source categories that may not have been included in TRI.⁶

Table 3-3 presents a compilation of SIC codes that have been associated with mercury emissions.^{5,6} This table lists the SIC codes that were identified as a potential source of mercury emissions, provides a description of the SIC code, and identifies other emission sources that do not have an assigned SIC code.^{5,6}

Table 3-4 provides a summary of the estimated 1990 nationwide mercury emissions for those source categories where adequate information was available (i.e., emission factors and production data). Appendix A presents the data used for each of these estimates, assumptions, and the emission calculations for each of these source categories. The estimated emissions were based on emission factors provided in this document or calculated from source test data and appropriate process information, if available.

The total 1990 nationwide mercury emissions estimate was 302 Mg (332 tons) for those source categories identified in Table 3-4. The five specific sources emitting the largest quantities of mercury were coal combustion (111 Mg; 122 tons), medical waste incineration (59 Mg; 65 tons), municipal waste combustion (58 Mg; 64 tons), oil combustion (14 Mg; 15 tons), and paint application (13 Mg, 15 tons). These five specific sources combined accounted for approximately 84 percent of the total mercury emissions in Table 3-4.

Of the five major source categories, mercury emissions resulting from combustion sources accounted for a total of 243 Mg (268 tons) or approximately 80 percent of the total estimated emissions. Within the combustion source category, the major contributor to mercury emissions was from the combustion of coal, followed by municipal waste, and medical waste. Coal combustion accounted for 46 percent of the total emissions from combustion

TABLE 3-3. POTENTIAL SOURCE CATEGORIES OF MERCURY EMISSIONS

SIC Code	Description
0721	Crop planting and protecting
1021	Copper ores
1031	Lead and zinc ores
1099	Metal ores
12	COAL MINING
1221	Bituminous coal and lignite surface
1222	Bituminous coal underground
1311	Oil shale retorting
2611	Pulp mills
2621	Paper mills
2812	Alkalines and chlorine
2813	Industrial gases
2816	Inorganic pigments
2819	Industrial inorganic chemicals
2821	Plastic materials and resins
2822	Synthetic rubber
2833	Medicinals and botanicals
2834	Pharmaceutical preparations
2842	Polishes and sanitation goods
2851	Paints and allied products
286	Industrial organic chemicals
2865	Cyclic crudes and intermediates
2869	Industrial organic chemicals
2873	Nitrogenous fertilizers
2879	Agricultural chemicals
2892	Explosives
2911	Petroleum refining
2951	Asphalt paving mixtures and blocks
2952	Asphalt felts and coatings
308	Miscellaneous plastics products
3087	Custom compound purchased resins
32	STONE, CLAY, AND GLASS PRODUCTS
3229	Pressed and blown glass

TABLE 3-3. (continued)

SIC Code	Description
3241	Cement, hydraulic
3274	Lime
3312	Blast furnaces and steel mills
3313	Ferroalloy production
332	Iron and steel foundries
3321	Gray and ductile iron foundries
3331	Primary copper
3339	Primary nonferrous metals
3341	Secondary nonferrous metals
3366	Copper foundries
3465	Automotive stampings
3469	Non-ferrous foundries
3471	Plating and polishing
3499	Fabricated metal products
36	ELECTRONIC AND OTHER ELECTRIC EQUIPMENT
361	Electric transmission and distribution equipment
3629	Electrical industrial apparatus
364	Electric lighting and wiring equipment
3641	Electric lamps
3643	Current-carrying wiring devices
3674	Semiconductors and related devices
3679	Electronic components
3691	Storage batteries
3692	Primary batteries, dry and wet
3699	Electrical equipment and supplies
3711	Motor vehicles and car bodies
38	INSTRUMENTS AND RELATED PRODUCTS
3821	Laboratory apparatus and furniture
3822	Environmental controls
3829	Measuring and controlling devices
3841	Surgical and medical instruments
40	RAILROAD TRANSPORTATION
4911	Electric services

TABLE 3-3. (continued)

SIC Code	Description
4941	Water supply
4952	Sewerage systems
4953	Refuse systems (includes municipal waste combustion, sewage sludge incineration, and medical waste incineration)
5094	Jewelry and precious stones
80	HEALTH SERVICES
8021	Offices and clinics of dentists
8221	Colleges and universities
8731	Commercial physical research
9223	Correctional institutions
9511	Air, water, and solid waste management
9661	Space research and technology
9711	National security
--	Coal combustion
--	General laboratory use
--	Natural gas combustion
--	Oil combustion
--	Wood combustion

Source: References 5 and 6.

**TABLE 3-4. ESTIMATED 1990 NATIONWIDE MERCURY EMISSIONS
FOR SELECTED SOURCE CATEGORIES**

Source category	Mercury emissions		Basis
	Mg/yr	Tons/yr	
<u>Mercury and mercury compound production</u>			
Primary mercury production	NA		No emission factors
Secondary mercury production	5.7	6.3	Appendix A
Mercury compound production	NA		No emission factors
<u>Major uses of mercury</u>			
Chlor-alkali production	9.3	10.2	Appendix A
Battery manufacture	0.1	0.1	Appendix A
Electrical uses	9.0	9.9	Appendix A
<u>Combustion sources</u>			
Coal combustion	111	122	Appendix A
Oil combustion	13.5	14.9	Appendix A
Natural gas combustion	0	0	No emission factor
Municipal waste combustion	57.9	63.8	Appendix A
Sewage sludge combustion	1.6	1.8	Appendix A
Medical waste combustion	58.7	64.7	Appendix A
Wood combustion	0.3	0.3	Appendix A
<u>Miscellaneous manufacturing processes</u>			
Portland cement production	5.6	6.2	Appendix A
Lime manufacturing	0.6	0.7	Appendix A
Carbon black production	0.2	0.2	Appendix A
Byproduct coke production	NA		No emission factor
Primary lead smelting	8.2	9.0	Appendix A
Primary copper smelting	NA		No emission factor
Petroleum refining	NA		No emission factor
Oil shale retorting	0	0	Appendix A
Geothermal power plants	1.3	1.4	Appendix A
<u>Other miscellaneous sources</u>			
Mercury catalysts	0	0	Appendix A
Dental alloys	0.5	0.6	Appendix A
Mobile sources	4.5	5.0	Appendix A
Crematories	0.4	0.4	Appendix A
Paint	13.2	14.6	Appendix A
TOTAL	302	332	

NA = Non-applicable

sources and 37 percent of the total emissions from all source categories. The other five combustion sources, wood, municipal waste, medical waste, sewage sludge, and oil, collectively accounted for 54 percent of the total emissions from combustion sources and 44 percent of the total emissions from all source categories. The paint category was the only other source category to show estimated mercury emissions greater than 10 Mg (11 tons).

SECTION 4

EMISSIONS FROM MERCURY PRODUCTION

In 1991, the total supply of metallic mercury (Hg) in the United States was 1,416 Mg (1,558 tons).⁷ Of this total, approximately 51 percent was from depletion of the former mercury ore producer stockpile and mercury production as a byproduct of gold ore mining. Approximately 24 percent resulted from secondary production processes (reclamation); the remaining 25 percent was due to change in industry stocks, Government stockpile excesses, and imports (see Section 3, Figure 3-1). There were 13 facilities in the United States that produced mercury, primarily on the East Coast and in the West. Of these facilities, eight produced mercury as a byproduct from gold ore and five were mercury reclaimers. Emissions of mercury occur primarily during the metal production process and during mercury reclamation processes.

This section presents information on the identification of the producers and descriptions of typical production processes. Process flow diagrams are given as appropriate, and any known emission control practices are presented. Estimates of mercury emissions are provided in the form of emission factors wherever data were available.

4.1 PRIMARY MERCURY PRODUCTION

Mercury is currently produced in the U.S. only as a byproduct from the mining of gold ores. Production from mercury ore had occurred at the McDermitt Mine in McDermitt, Nevada, but the mine ceased operation in 1990. During the past 2 years, the equipment has been dismantled and sold, landfilled, or scrapped,

and all major buildings have been removed. In 1991, eight U.S. gold mines produced metallic mercury as a byproduct; Table 4-1 presents a list of these gold mines.⁷ As shown in the table, six of the mines are in Nevada, one is in California, and one is in Utah. None of the operating gold mines in Alaska produce byproduct mercury. In 1991, the quantity of mercury recovered at these mines was reported by the Bureau of Mines to be 58 Mg (64 tons).

4.1.1 Process Description

Production from Mercury Ores--

No process description of the McDermitt Mine operation will be presented because the existing equipment has been removed from the site, thereby negating any possibility that the facility could reopen at a future date using the same process and equipment.

Byproduct from Gold Ores--

Since the closure of the McDermitt Mine, recovery of mercury as a byproduct from gold ores is the only remaining ore-based production process. All other processes for mercury production are either reclamation or government surplus stock. A simplified flow diagram depicting mercury recovery from a gold cyanidation process is shown in Figure 4-1.

The incoming gold ore is crushed using a series of jaw crushers, cone crushers, and ball mills. If the incoming ore is an oxide-based ore, no pretreatment is required, and the crushed ore is mixed with water and sent to the classifier. If the ore is a sulfide-based ore, it must be pretreated using either a fluid-bed or multiple hearth pretreatment furnace (roaster) to convert metallic sulfides to metallic oxides.⁸ The exhaust gas from either of these units is sent through wet electrostatic precipitators (ESP's) and, if necessary, through carbon condensers. The exhaust gas then passes through a scrubber in

**TABLE 4-1. BYPRODUCT MERCURY-PRODUCING GOLD MINES IN
THE UNITED STATES IN 1991**

Mine	County and State	Operator
Getchell	Humboldt, NV	FMC Gold Co.
Carlin Mines Complex	Eureka, NV	Newmont Gold Co.
Hog Ranch	Washoe, NV	Western Hog Ranch Co.
Jerritt Canyon (Enfield Bell)	Elko, NV	Independence Mining Co., Inc.
McLaughlin	Napa, CA	Homestake Mining Co.
Mercur	Tooele, UT	Barrick Mercur Gold Mines, Inc.
Paradise Peak	Nye, NV	FMC Gold Co.
Pinson and Kramer Hill	Humboldt, NV	Pinson Mining Co.

Source: Reference 7.

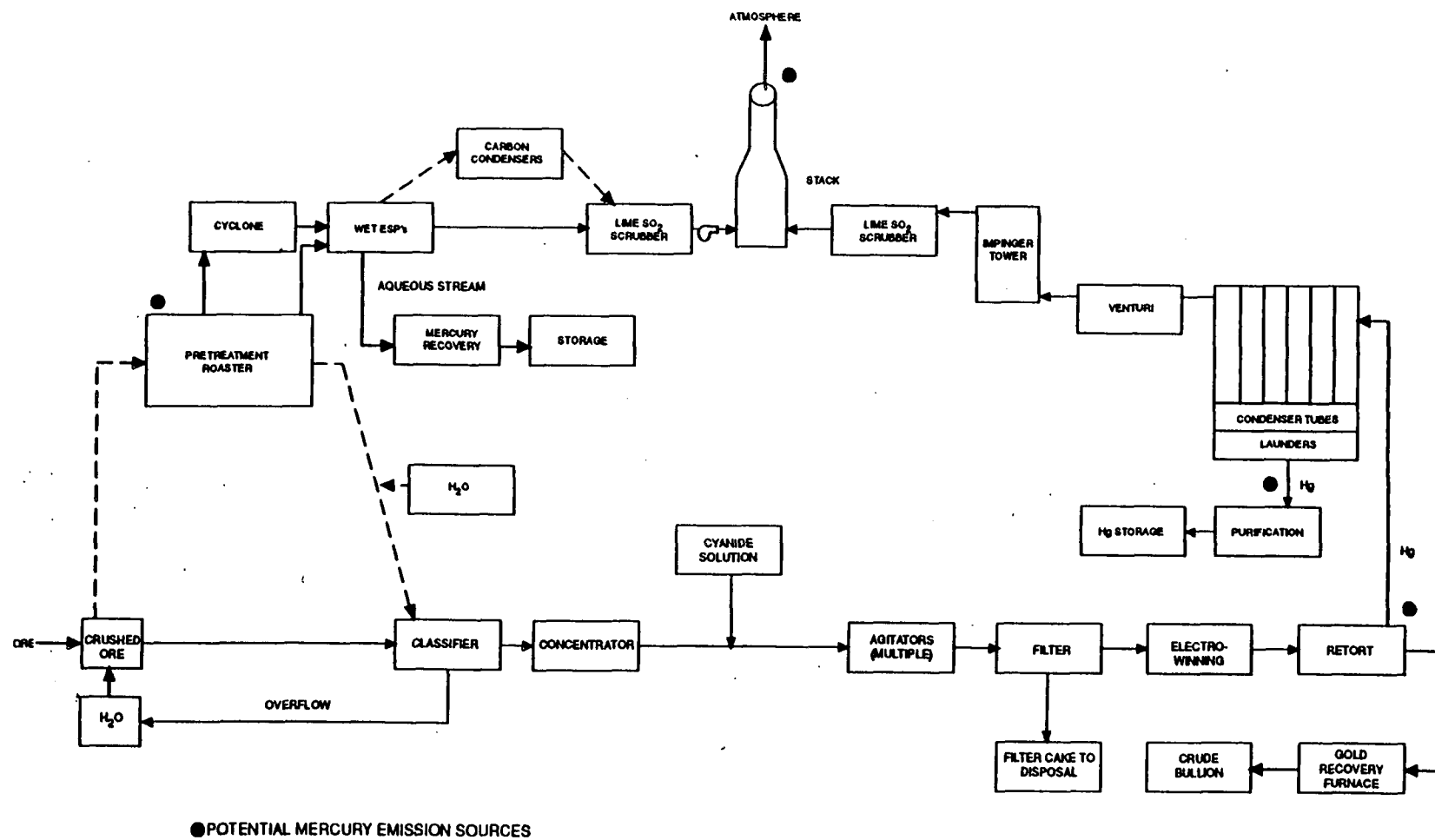


Figure 4-1. Major components of mercury recovery from gold ores.

which SO_2 is removed by lime prior to discharging to the atmosphere. If the treated sulfide ore is high in mercury content, the primary mercury recovery process occurs from the wet ESP's. If the concentration is sufficiently low, no attempt is made to recover the mercury for sale. The pretreated ore is mixed with water and sent to the classifier, where the ore is separated (classified) according to size. Ore pieces too large to continue in the process are returned to the crusher operation.

From the classifier, the slurry passes through a concentrator to reduce the water content and then to a series of agitators containing the cyanide leach solution. From the agitators, the slurry is filtered, the filter cake sent to disposal, and the filtrate containing the gold and mercury is transferred to the electrowinning process. If the carbon-in-pulp (CIP) process is used, the cyanide pulp in the agitators is treated with activated carbon to adsorb the gold and mercury. The carbon is filtered from the agitator tanks and treated with an alkaline cyanide-alcohol solution to desorb the metals. This liquid is then transferred to the electrowinning tanks. In the electrowinning process, the gold and mercury are electrodeposited onto a stainless steel wool cathode, which is sent to a retort to remove mercury and other volatile impurities. The stainless steel wool containing the gold is transferred from the retort to a separate smelting furnace where the gold is melted and recovered as crude bullion.

The exhaust gas from the retort, containing mercury, SO_2 , particulate, water vapor, and other volatile components, passes through condenser tubes where the mercury condenses as a liquid and is collected under water in the launders. From the launders, the mercury is purified and sent to storage. After passing through the condenser tubes, the exhaust gas goes through a venturi and impinger tower to remove particulate and water droplets and then moves through the SO_2 scrubber prior to discharging to the atmosphere.

Gold ores in open heaps and dumps can also be treated by cyanide leaching. In this process, the gold ore is placed on a leaching pad and sprayed with the cyanide solution. The solution permeates down through the ore to a collection system on the pad, and the resulting pregnant solution is sent to a solution pond. From this pond, the leachate liquors, which contain gold and mercury, are transferred to the gold recovery area where the liquor is filtered and sent to the electrowinning process.

4.1.2 Emission Control Measures

Potential sources of mercury emissions from gold processing facilities are at locations where furnaces, retorts, or other high temperature sources are used in the process and where the mercury is removed from the launders. The treated gas discharged to the atmosphere is also a source of mercury emissions. These sources are denoted in Figure 4-1 with a solid circle.

When pretreatment roasting is required, the exhaust gases from the furnace pass through a cyclone to remove particulate and then move through wet ESP's to remove arsenic, mercury, and some of the SO_2 . If the mercury concentration in the gold ore is high, the ESP's will not remove all of the mercury, and an activated carbon adsorber bed may be required for additional mercury removal. The gas passes through a lime scrubber to remove SO_2 ; if the SO_2 concentration is low, a caustic scrubber may be used.⁸ From the scrubber, the gas is discharged through the stack to the atmosphere. Essentially the same emission control measures are used from the exhaust gas from the retort. After the gas passes through the condenser tubes to remove the mercury, a venturi and a cyclone are used to remove particulate and water droplets. These controls are followed by the lime scrubber to remove the SO_2 prior to discharging the clean gas to the atmosphere.

4.1.3 Emissions

The major sources of mercury emissions for gold processing facilities are the pretreatment roaster (if required) and the retort. Other sources of emissions are from the purification process after removal of mercury from the launders and the stack emissions to the atmosphere. No emissions data have been published for facilities producing mercury as a byproduct from gold ore. Furthermore, limited data were published for emission sources at facilities that produced mercury from the primary ore. Emission factors for three potential sources in the production process from mercury ore were published in 1973.⁹ These emission factors are presented in Table 4-2 and were based on the quantity of ore processed, not on the quantity of mercury produced. No information was provided to equate the quantity of ore processed to quantity of mercury produced.¹⁰

TABLE 4-2. MERCURY EMISSION FACTORS FOR PRIMARY MERCURY PRODUCTION

Process	Emission factor		Notes
	kg/Mg ore	lb/ton ore	
Cleaning launders	0.01	0.02	Uncontrolled emissions ^a
Retort operation	0.001	0.002	Uncontrolled emissions ^a
Stack	0.16	0.32	Uncontrolled emissions ^a

^aAs stated in Reference 9.

Source: Reference 9.

Emission tests were conducted in the condenser stack at the McDermitt Mine in 1981, and the average mercury emission rate was calculated to be 816 grams/day (g/d) [1.8 pounds/day (lb/d)]. Based on eight furnace runs per year, each of 15 days duration, and a production of 750 tons of mercury in 1981, the calculated emission rate would be 0.13 kg/Mg (0.3 lb/ton) of mercury produced.¹¹ The emission factors shown in Table 4-2 are based on tons of ore processed, whereas the rate calculated from the emission tests at McDermitt Mine is based on tons of mercury produced.

Extreme caution should be exercised in using any of these emission factors from primary mercury production for mercury production as a byproduct of gold mining. The treatment techniques to recover the mercury, after the mercury has been vaporized in a retort or furnace, and the emission sources are very similar for both processes, but the overall production process is different.

4.2 SECONDARY MERCURY PRODUCTION

Secondary mercury production involves the processing of scrapped mercury-containing products, industrial waste and scrap, and scrap mercury from Government stocks. Major sources of recycled mercury include dental amalgams and scrap mercury from instrument and electrical manufacturers (lamps and switches), wastes and sludges from research laboratories and electrolytic refining plants, and mercury batteries.²

In 1991, 122 Mg (134 tons) of mercury was recycled from industrial scrap and 215 Mg (237 tons) from Government stocks.⁷ These totals do not include in-house mercury reclamation at industrial plants using mercury. Table 4-3 presents a list of the five major companies that were involved in secondary mercury production (mercury recyclers) in 1989.¹²

TABLE 4-3. U.S. MERCURY RECYCLERS IN 1989

Adrow Chemical Company	Wanaque, NJ
Bethlehem Apparatus Company, Inc.	Hellertown, PA
D. F. Goldsmith Chemical and Metals Corp.	Evanston, IL
Mercury Refining Company, Inc.	Latham, NY
Wood Ridge Chemical Company	Newark, NJ

Source: Reference 12.

4.2.1 Process Description

Secondary mercury production (recycling) can be accomplished by one of two general methods: chemical treatment or thermal treatment.² Chemical treatment can encompass several methods for processing aqueous mercury-containing waste streams. To precipitate metallic mercury, the waste stream can be treated with sodium borohydride or it can be passed through a zinc-dust bed. Mercuric sulfide can also be precipitated from the waste streams by treatment with a water-soluble sulfide, such as sodium sulfide. Ion-exchange systems can be used to recover ionic mercury for reuse, while mercuric ions can be trapped by treatment with chemically modified cellulose.¹³

The most common method to recover metallic mercury for recycling is thermal treatment. Figure 4-2 provides a general process diagram for secondary mercury recovery at a battery plant. This process is generally representative of the recovery of mercury by thermal treatment of scrap. Generally, the mercury-containing scrap is reduced in size and is heated in retorts or furnaces at about 538°C (1000°F) to vaporize the mercury. The mercury vapors are condensed by water-cooled condensers and collected under water.^{14,15}

Vapors from the condenser, which may contain particulate, organic compounds, and possibly other volatile materials from the scrap, are combined with vapors from the mercury collector line. This combined vapor stream is passed through an aqueous scrubber to remove particulate and acid gases (e.g., HCl, SO₂). From the aqueous scrubber, the vapor stream passes through a charcoal filter to remove organic components prior to discharging into the atmosphere.¹⁴

The collected mercury is further purified by distillation, collected, and then transferred to the filling area. In the filling area, special filling devices are used to bottle small

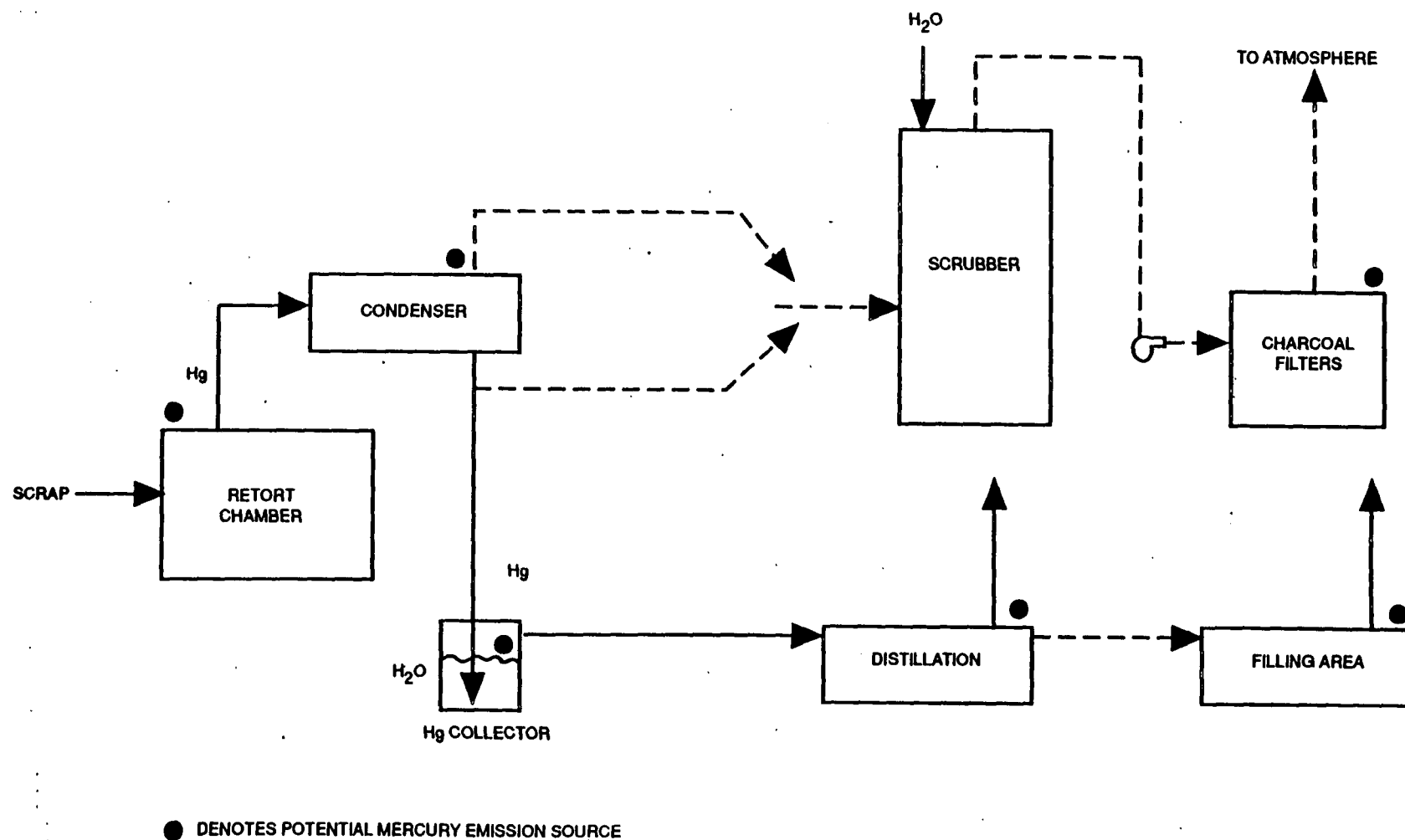


Figure 4-2. Process flow diagram for secondary recovery at a battery plant.¹⁵

quantities, usually 0.464 kg (1 lb) or 2.3 kg (5 lb) of distilled mercury. With these filling devices, the mercury flows by gravity through tubing from a holding tank into the flask until the flask overflows into an overflow bottle. The desired amount of mercury is dispensed into the shipping bottle by opening a valve at the bottom of the flask. The shipping bottle is then immediately capped after the filling and sent to the storage area.¹⁵

4.2.2 Emission Control Measures

Information on specific emission control measures is very limited and site specific. If a scrubber is used, as shown in Figure 4-2, mercury vapor or droplets in the exhaust gas may be removed by condensation in the spray. There is no information to indicate that chemical filters would be effective in removing mercury vapors.¹⁵ No information was found for other control measures that are being used in secondary mercury production processes. Concentrations in the workroom air due to mercury vapor emissions from the hot retort may be reduced by the following methods: containment, local exhaust ventilation, dilution ventilation, isolation, and/or personal protective equipment. No information was provided to indicate that these systems are followed by any type of emission control device.¹⁵ Vapor emissions due to mercury transfer during the distillation or filling stages may be reduced by containment, ventilation (local exhaust or ventilation), or temperature control.

4.2.3 Emissions

During secondary mercury production, emissions may potentially occur from the following sources: retort or furnace operations, distillation, and discharge to the atmosphere from the charcoal filters.^{14,15} The major mercury emission sources are due to condenser exhaust and vapor emissions that occur during unloading of the retort chamber. These sources are

indicated in Figure 4-2 by a solid circle. Mercury emissions can also occur in the filling area when the flask overflows and during the bottling process.

The secondary mercury production process has not undergone any recent emission tests so there is virtually no data for this process. In 1973, emission factors were estimated to be 20 kg (40 lb) per megagram (ton) of mercury processed due to uncontrolled emissions over the entire process.⁹ These data should be used with extreme caution because they are very old and industry practices have changed.

Data for emission levels in a limited number of facilities have been reported.¹⁴ For example, a Pennsylvania recycler used a water spray to control mercury emissions from the condenser exhaust. Mercury emissions after the spray were 840 g/d (1.85 lb/d). A New York plant was estimated to emit less than 1 g/d (<0.002 lb/d) to the atmosphere.¹⁴ However, these data, in terms of weight of mercury emitted per day, are not useful for developing emission factors because no process or production data were available for these facilities.

The only mercury emission data reported in the 1990 TRI was for Mercury Refining Company, Inc., in Albany (Latham), New York.⁵ This facility reported plant emissions to the atmosphere of 227 kg (500 lb) for 1990.

4.3 MERCURY COMPOUNDS PRODUCTION

The production of mercury compounds presents a potential source of release of mercury into the atmosphere. Table 4-4 lists several producers of inorganic and organic mercury compounds. Only one facility reported significant mercury emissions in the 1990 TRI: Mallinkrodt Specialty Chemicals Co. in Erie, PA reported 226.8 kg (500 lb).^{5,16}

TABLE 4-4. MERCURY COMPOUND PRODUCERS

Producer	Location	Compound(s)
Atochem North America, Inc., Chemical Specialties Division	Tulsa, OK	HgF ₂
Atomergic Chemetals Corp.	Farmingdale, NY	Thimerosal (Merthiolate)
Cambrex Corp., CasChem, Inc., Subsidiary (formerly Cosan Chem. Corp.)	Carlstadt, NJ	Phenylmercury acetate (PMA), Phenylmercury oleate
W.A. Cleary Corp.	Somerset, NJ	PMA
Deepwater, Inc.	Carson, CA	HgI ₂
GFS Chemicals, Inc.	Columbus, OH	HgBr ₂ , HgI ₂ , Hg(NO ₃) ₂ , HgSO ₄
Hüls America, Inc.	Elizabeth, NJ	PMA
Imsera Group, Inc., Mallinkrodt Inc., Subsidiary, Mallinkrodt Specialty Chem. Co.	Erie, PA	HgCl ₂ on carbon support (catalyst for vinyl chloride manufacture)
Morton International, Inc., Specialty Chemicals Group, Advanced Materials, CVD Inc. Subsidiary	Woburn, MA	Highly purified dimethylmercury, (CH ₃) ₂ Hg, for chemical vapor deposition (CVD) of thin films
Polychemical Laboratories, Inc.	Melville, NY	Thimerosal (Merthiolate)
R.S.A Corporation	Ardsley, NY	Hg(SCN) ₂
Troy Chemical Corp.	Newark, NJ	PMA

Source: Reference 16.

4.3.1 Process Description

Numerous inorganic mercury compounds are produced annually in the U.S. using metallic mercury as the starting material. The production processes for mercuric chloride and mercuric oxide were selected to serve as typical examples because both of these compounds are common mercury compounds that are annually produced in large quantities. The production processes for each compound have been studied at Troy Chemical Corporation.¹⁷ Phenylmercuric acetate is one of the most common organomercuric compounds produced in the U.S. The production method for this compound was also selected as a typical process because of the quantities produced, and the process has been studied.¹⁷ A synopsis of

these three production processes is provided below; additional information is provided in Reference 15.

Mercuric Chloride and Mercurous Chloride--

The production of these two compounds occurs by the direct reaction of mercury with chlorine gas according to the following equations:

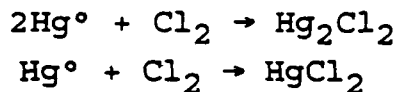


Figure 4-3 presents a process diagram for the production of mercuric chloride. Elemental mercury (Stream A) is pumped from a holding tank into a reactor where it reacts with excess chlorine gas (Stream B). The reaction products (Stream C) are ducted to a precipitation unit where the dry product (HgCl_2) settles and is raked out. Mercuric chloride (Stream D) is packaged and sealed in drums for shipping.^{15,17} The exhaust from the reactor (Stream E) is sent to a caustic scrubber where unreacted mercury is recovered and is then recycled back (Stream F) to the reactor. A similar process is used to produce mercurous chloride.

Mercuric Oxide--

Two different processes have been used for mercuric oxide production: (1) production via mercuric chloride and (2) production via mercuric nitrate intermediates. Both processes are shown in Figure 4-4.

In production via mercuric chloride, mercury (Stream A) and chlorine in brine solution (Stream B) are mixed in a reactor where mercuric chloride is produced in solution by oxidation of the liquid mercury. The mercuric chloride (Stream C) is then transferred to a second reactor and an aqueous caustic (NaOH) solution is added, resulting in the formation of

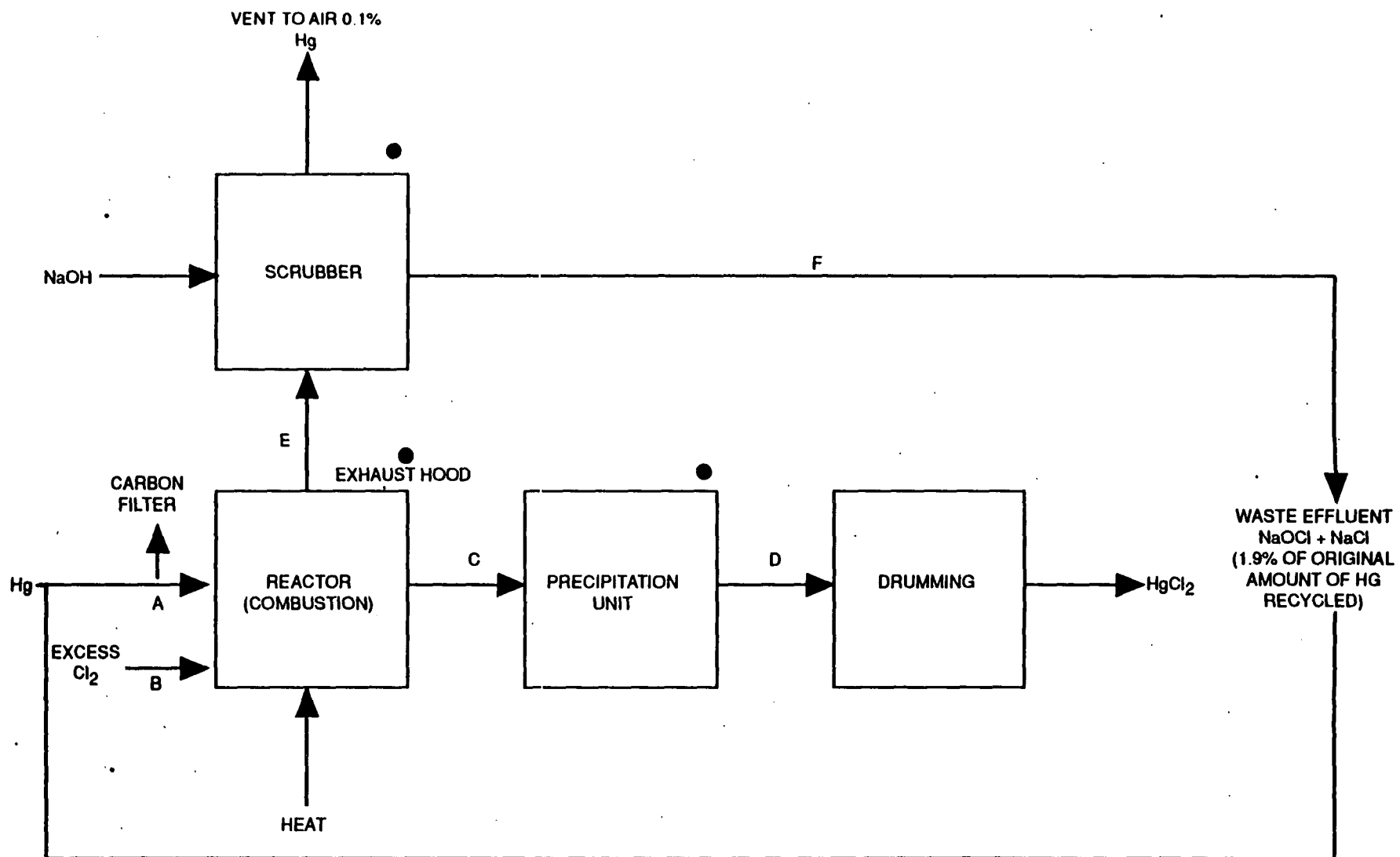


Figure 4-3. Mercuric/mercurous chloride production.

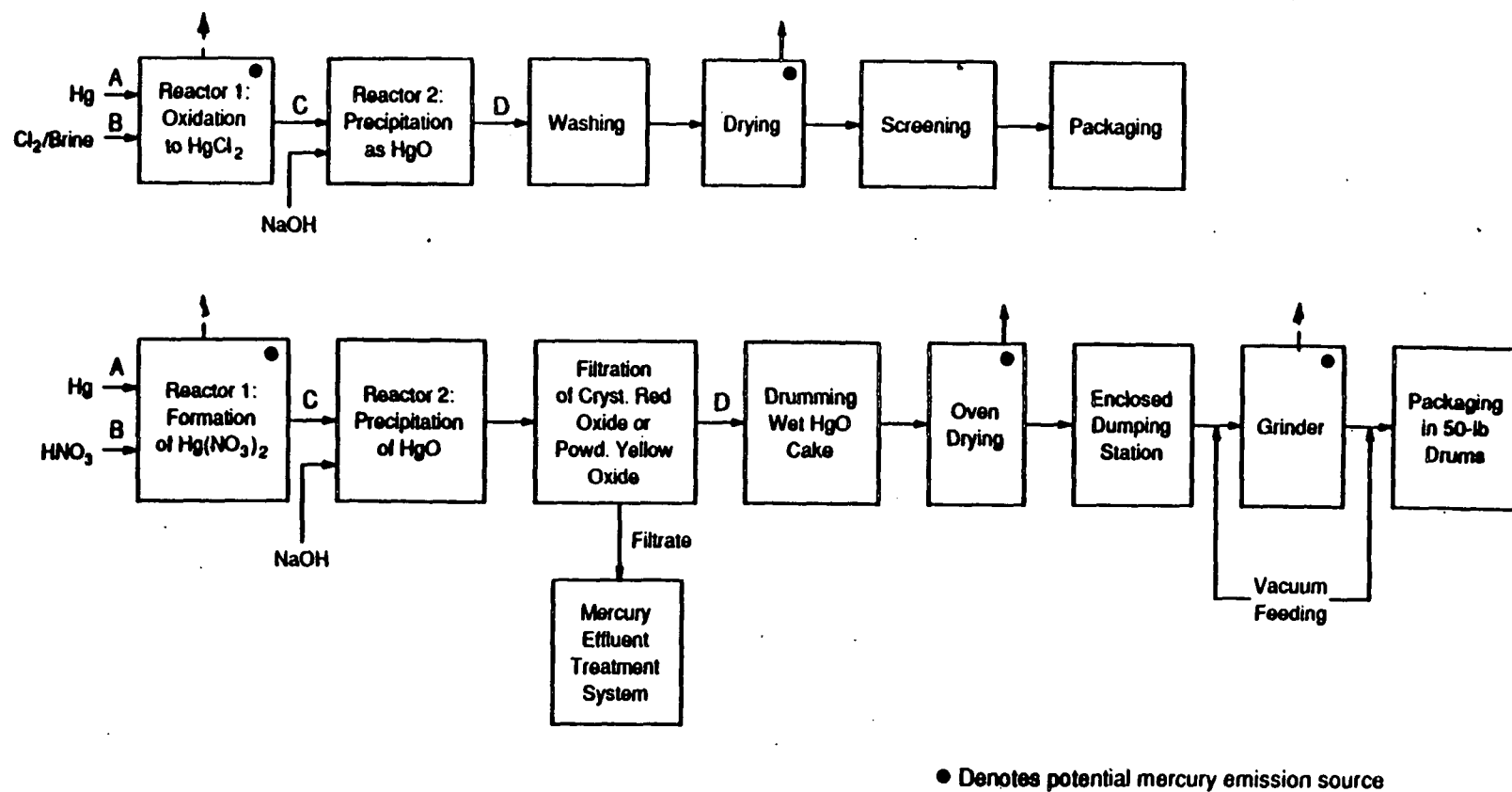


Figure 4-4. Mercuric oxide production via mercuric chloride and mercuric nitrate intermediates.

mercuric oxide. The mercuric oxide precipitate (Stream D) is then washed, dried, screened, and packaged.¹⁴

In the process using the mercuric nitrate intermediate, (also shown in Figure 4-4), mercury (Stream A) and nitric acid (Stream B) are combined in a reactor, resulting in the formation of mercuric nitrate ($\text{Hg}(\text{NO}_3)_2$). The mercuric nitrate (Stream C) is then transferred to a second reactor where mercuric oxide is precipitated by adding an aqueous caustic solution (NaOH). The mercuric oxide (Stream D) is washed, dried, ground, and packaged.¹⁵

Phenylmercuric Acetate--

Phenylmercuric acetate (PMA) can be produced by one of two processes. In the most common production process, mercuric oxide is transferred to a glass-lined reactor and refluxed in a boiling mixture of acetic acid ($\text{CH}_3\text{CO}_2\text{H}$) and benzene (C_6H_6) at approximately 80°C (176°F). The reaction proceeds according to the following steps:

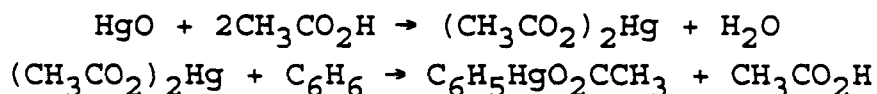


Figure 4-5 presents a process flow diagram for this PMA production process using 1982 technology, which is the most recent available description.¹⁷

In the less common process, mercuric acetate is refluxed with a mixture of benzene and acetic acid. Aside from the initial reactions to form the PMA, the subsequent processes follow the same procedure.

When the reaction is complete, the PMA solution is filtered to remove any solid material, transferred to a precipitator, and the solid PMA is filtered to yield a wet filter cake. The wet PMA filter cake is transported to a vacuum drying oven to produce

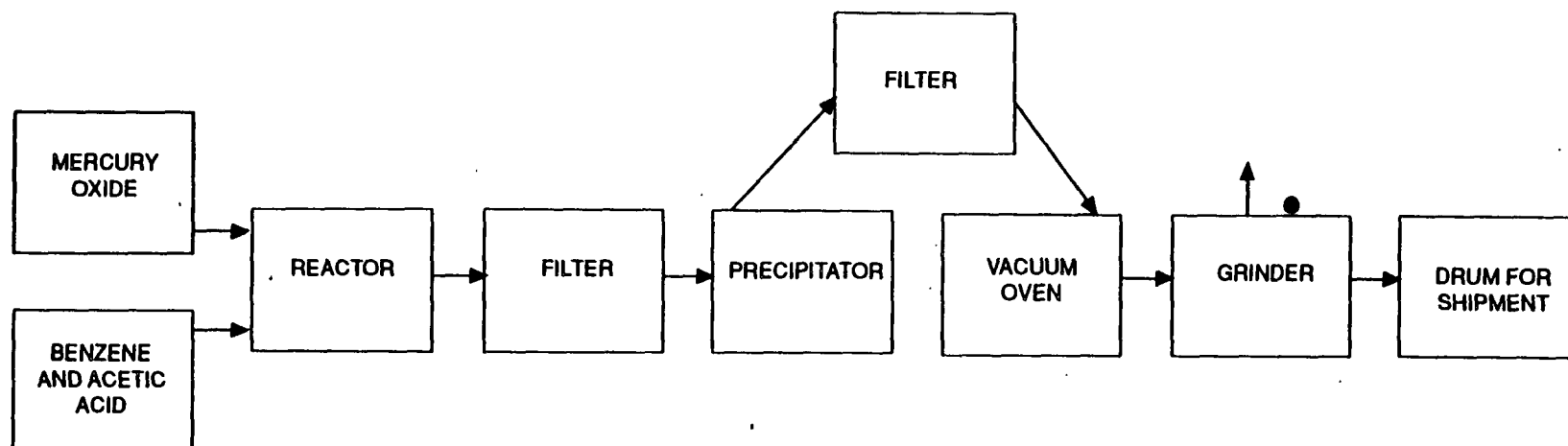


Figure 4-5. Process flow diagram for production of phenylmercuric acetate.

the final dry product. After drying, the PMA is ground and packed in fiber drums for shipment.

4.3.2 Emission Control Measures

No information was found on specific emission control devices to remove or treat the mercury emissions. Only methods designed to reduce the workplace concentrations without subsequent treatment were presented.¹⁵ Methods suitable for reducing workroom air concentrations of mercury during the production of mercury compounds are similar to those described for primary and secondary mercury processing. Particulate concentrations in the workplace resulting from several process operations (e.g., addition of dry chemicals to reactors, filtration, drying, grinding, and packaging) may be reduced by containment, exhaust ventilation, dilution ventilation, and personal protective equipment. Vapor concentrations from reactors may be reduced by containment. Mercury vapor concentrations in the workplace from mercury transfer to reactors may be reduced by containment.¹⁵

In the production and packaging of PMA, local exhaust ventilation is used to reduce mercury concentrations in workroom air at the loading hopper for the grinder, at the station where the dried PMA is drummed, and at the drum loading stand where PMA exits the grinder. Local exhaust ventilation is used at the reactor charging station and at the blender, where dilute PMA is discharged.¹⁵

During mercuric oxide production, grinding and packaging operations are done in an enclosed system under vacuum, including material transfers. A cyclone dust collector separates fine dust from product-sized HgO particles, which are channeled to the packaging station. The fine dust is collected and transferred periodically to fiber drums. The vacuum pump discharge also goes

through a cyclone dust separator before it exhausts to the roof. Collected dust is recycled through the grinder.¹⁷

4.3.3 Emissions

During the production of these compounds, emissions of mercury vapor and particulate mercury compounds may occur at the following sources: reactors, driers, filters, grinders, and transfer operations. These emission sources are indicated in Figures 4-3, 4-4, and 4-5 by a solid circle.

Emission factors are not available for production of mercury compounds. No test data for mercury emissions were found that would permit the calculation of emission factors.

SECTION 5

EMISSIONS FROM MAJOR USES OF MERCURY

Emissions from industrial processes that use mercury are discussed in this section. Based on the 1991 U.S. industrial demand figures presented in Figure 3-1 in Section 3, mercury has four major commercial uses. These are: (1) chlor-alkali production using the mercury cell process, (2) primary battery production, (3) production of measuring and control instruments, and (4) production of electrical lighting, wiring devices, and electrical switches. This section is divided into four subsections, one devoted to each major use. Each of the subsections presents a general discussion of the production process and where mercury is used in the process, descriptions of existing mercury emission control measures, and estimates of mercury emission factors. The level of detail will vary according to the availability of information, particularly for emissions where data may be incomplete or absent.

5.1 CHLOR-ALKALI PRODUCTION USING THE MERCURY CELL PROCESS

In 1988, the mercury cell process accounted for 17 percent of all U.S. chlorine production. The diaphragm cell accounted for 76 percent, the membrane cell for 5 percent, and other methods for 2 percent. However, recent trends are moving away from mercury cell production toward the more environmentally acceptable membrane cell process. Only the mercury cell process uses mercury. The more modern membrane cell process is more energy efficient compared to the diaphragm cell or mercury cell and produces a higher quality product.¹⁸ Table 5-1 presents the

TABLE 5-1. 1990 MERCURY CELL CHLOR-ALKALI PRODUCTION FACILITIES

FACILITY	LOCATION	CAPACITY,	
		10 ³ Mg/yr	10 ³ TONS/YR
Akzo Chemicals, Inc.	Le Moyne, AL	70	78
Georgia-Pacific Corp., Chemical Division	Bellingham, WA	82	90
BF Goodrich, Chemical Division	Calvert City, KY	109	120
Hanlin Group, Inc., LCP Chemicals Division	Acme, NC	48	53
	Brunswick, GA	96	106
	Moundsville, WV	79	87
	Orrington, ME	76	80
Lin Chem, Inc.	Ashtabula, OH	36	40
Occidental Petroleum Corporation, Electrochemicals Division	Deer Park, TX	347	383
	Delaware City, DE	126	139
	Mobile, AL	34	37
	Mussell Shoals, AL	132	146
Olin Corporation, Olin Chemicals	Augusta, GA	102	112
	Charleston, TN	230	254
Pioneer Chlor-alkali Company, Inc.	St. Gabriel, LA	160	176
PPG Industries, Inc., Chemicals Group	Lake Charles, LA	1,041	1,148
	Natrium, WV	313	345
Vulcan Materials Company, Vulcan Chemicals Division	Port Edwards, WI	65	72
TOTAL		3,146	3,466

Source: Reference 16.

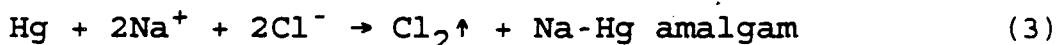
location and capacity of mercury cell chlor-alkali production facilities operating in 1991.¹⁶

5.1.1 Process Description^{14,18}

The mercury cell process consists of two electrochemical cells, the electrolyzer and the decomposer. A basic flow diagram for a mercury cell chlor-alkali production operation is shown in Figure 5-1.

Saturated (25.5 weight percent) purified sodium or potassium brine (Stream A) flows from the main brine saturation section, through the inlet end box, and into the electrolyzer cell. The cell is an elongated trough that is inclined approximately 1° to 2.5° with sides that are typically lined with rubber. Stationary activated titanium anodes are suspended from above into the brine; mercury, which is the cathode, flows concurrently with the brine over a steel base.

The electrochemical reaction that occurs at the titanium anodes is shown in equation (1); the reaction at the mercury cathode is shown in equation (2); and the overall reaction is shown in equation (3).



Chlorine gas (Stream B), formed at the electrolyzer anode, is collected for further treatment. The spent brine (Stream C) contains 21-22 weight percent NaCl and is recycled from the electrolyzer to the main brine saturation section through a dechlorination stage. Sodium forms an amalgam, containing from 0.25 to 0.5 percent sodium, at the electrolyzer cathode. The resulting amalgam flows into the outlet end box at the end of the electrolyzer. In the outlet end box, the amalgam is constantly

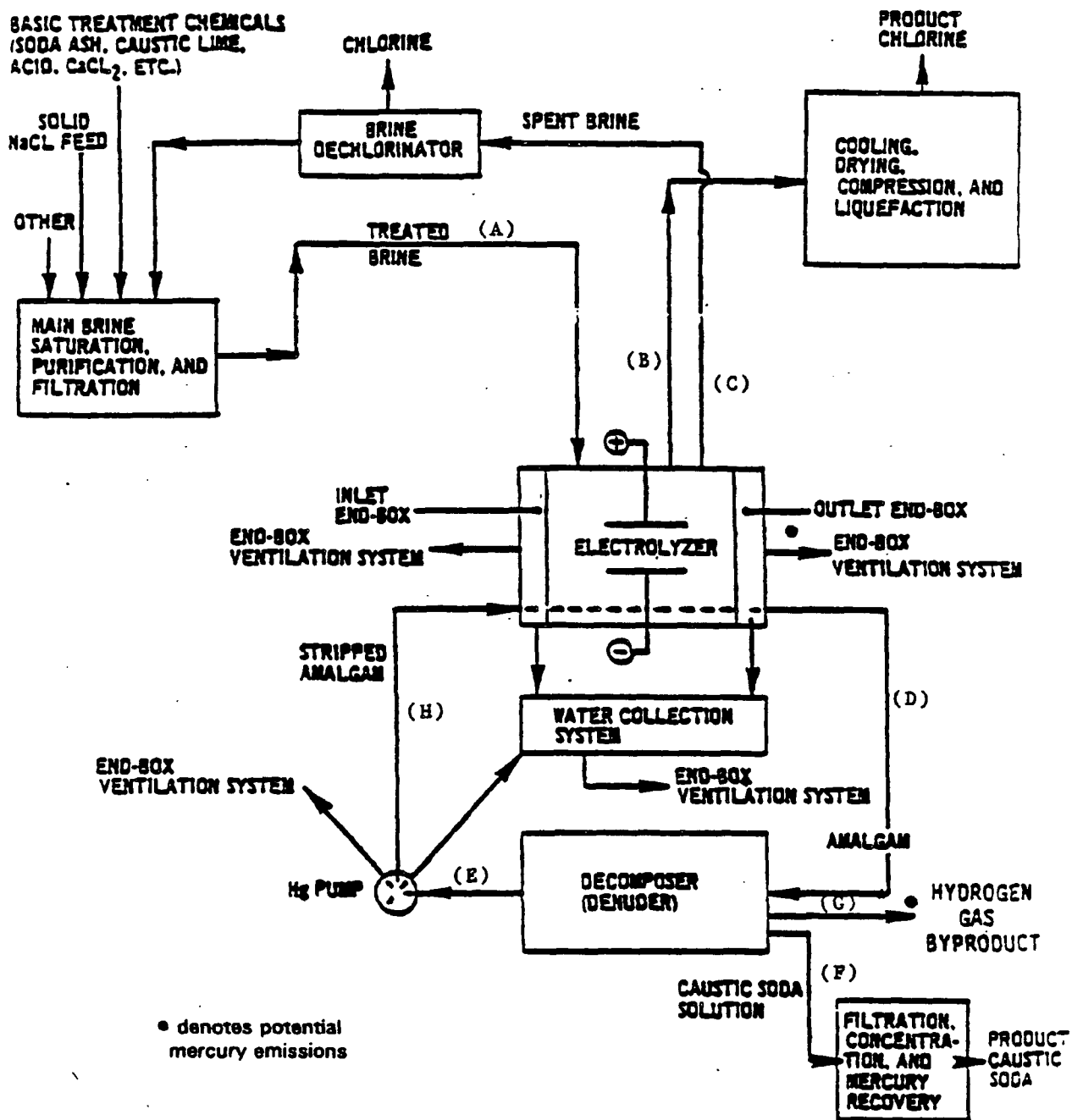


Figure 5-1. Basic flow diagram for a mercury-cell chlor-alkali operation.¹⁴

covered with an aqueous layer to reduce mercury emissions. The outlet end box also allows removal of a thick mercury "butter" that is formed by impurities. The sodium amalgam (Stream D) flows from the outlet end box into the second cell, the decomposer.

The decomposer is a short-circuited electrical cell in which the sodium amalgam acts as the anode and graphite as the cathode in sodium hydroxide solution. Fresh water is added to the decomposer where it reacts with the sodium amalgam to produce elemental mercury (Stream E), sodium hydroxide (Stream F), and byproduct hydrogen gas (Stream G). Stream E is then stripped of sodium and the mercury (Stream H) is recirculated back to the electrolyzer through the inlet end box. The inlet end box provides a convenient receptacle on the inlet end of the electrolyzer to receive the recycled mercury from the decomposer and keep it covered with an aqueous layer to reduce mercury emissions.

The caustic soda solution (Stream F) leaving the decomposer at a typical concentration of 50 weight percent is filtered and then further concentrated by evaporation. The byproduct hydrogen gas (Stream G) may be vented to the atmosphere, burned as a fuel, or used as a feed material for other processes.

5.1.2 Emission Control Measures¹⁴

Several control techniques can be employed to reduce the level of mercury in the hydrogen streams and in the ventilation stream from the end boxes. The most commonly used techniques are: (1) gas stream cooling, (2) mist eliminators, (3) scrubbers, and (4) adsorption on activated carbon or molecular sieves. Mercury vapor concentrations in the cell room air are not subject to specific emission control measures but rather are maintained at acceptable worker exposure levels using good housekeeping practices and equipment maintenance procedures.

Gas stream cooling may be used as the primary mercury control technique or as a preliminary removal step to be followed by a more efficient control device. The hydrogen gas stream from the decomposer exits the decomposer at 93° to 127°C (200° to 260°F) and passes into a primary cooler. In this indirect cooler, a shell-and-tube heat exchanger, ambient temperature water is used to cool the gas stream to 32° to 43°C (90° to 110°F). A knockout container following the cooler is used to collect the mercury. If additional mercury removal is desired, the gas stream may be passed through a more efficient cooler or another device. Direct or indirect coolers using chilled water or brine provide for more efficient mercury removal by decreasing the temperature of the gas stream to 3° to 13°C (37° to 55°F). If the gas stream is passed directly through a chilled water or brine solution, the mercury condenses and is collected under water or brine in lined containers. Mercury in the ventilation air from the end boxes can be removed using either direct or indirect cooling methods, but the direct method is used more frequently because the ventilation air from the exit end box contains mercuric chloride particulate. The direct cooling method not only cools the gas stream, but also removes the particulate from the stream. Regardless of the gas stream treated, the water or brine from direct contact coolers requires water treatment prior to reuse or discharge because of the dissolved mercury in the liquid.

Mist eliminators can be used to removed mercury droplets, water droplets, or particulate from the cooled gas streams. The most common type of eliminator used is a fiber pad enclosed by screens. With the fiber pad eliminator, trapped particles are removed by periodic spray washing of the pad and collection and treatment of the spray solution.

Scrubbers are used to chemically absorb the mercury from both the hydrogen stream and the end box ventilation streams. The scrubbing solution is either depleted brine from the mercury

cell or a sodium hypochlorite (NaOCl) solution. These solutions are used in either sieve plate scrubbing towers or packed-bed scrubbers. Mercury vapor and mist react with the sodium chloride or hypochlorite scrubbing solution to form water-soluble mercury complexes. If depleted brine is used, the brine solution is transferred from the scrubber to the mercury cell where it is mixed with fresh brine and the mercury is recovered by electrolysis in the cell.

Sulfur- and iodine-impregnated carbon adsorption systems are commonly used as a method to reduce the mercury levels in the hydrogen gas stream. Use of this method requires pretreatment of the gas stream by primary or secondary cooling followed by mist eliminators to remove about 90 percent of the mercury content of the gas stream. As the gas stream passes through the carbon adsorber, the mercury vapor is initially adsorbed by the carbon and then reacts with the sulfur or iodine to form the corresponding mercury sulfides or iodides. Depending upon the purity requirements and final use for the hydrogen gas, several adsorber beds may be connected in series to reduce the mercury levels to the very low parts per billion (ppb) range.

A proprietary molecular sieve adsorbant was used by five facilities to remove mercury from the hydrogen gas stream until 1984 when the supply of the adsorbant was discontinued by the manufacturer. The technique used dual adsorption beds in parallel such that while one bed was being used for adsorption, the other was being regenerated. A portion of the purified hydrogen gas from one adsorption bed was diverted, heated, and used to regenerate the second adsorption bed.

5.1.3 Emissions

The three primary sources of mercury emissions to the air are: (1) the byproduct hydrogen stream, (2) end box ventilation

air, and (3) cell room ventilation air. Emission sources (1) and (2) are indicated on Figure 5-1 by solid circles.

The byproduct hydrogen stream from the decomposer is saturated with mercury vapor and may also contain fine droplets of liquid mercury. The quantity of mercury emitted in the end box ventilation air depends on the degree of mercury saturation and the volumetric flow rate of the air. The amount of mercury in the cell room ventilation air is variable and comes from many sources, including end box sampling, removal of mercury butter from end boxes, maintenance operations, mercury spills, equipment leaks, cell failure, and other unusual circumstances.¹⁴

The only source of data for mercury emissions from chlor-alkali production facilities was a 1984 EPA report.¹⁴ This report contained test data from 21 chlor-alkali production facilities. The emission rates presented in Table 5-2 were calculated based on these test data. Emission control measures employed at the facilities ranged from no controls to a combination of control methods. The dates of the emission tests ranged from 1973 to 1983; however, more recent emission test data were not available. The emission rates presented in Table 5-2 represent mercury emissions per day. Emission factors were not calculated using the emission rate data because the chlorine production rates cited in the report for each of the facilities appear to be based on process design capacity values rather than actual production levels during the test. Use of prorated process design capacity data for daily production rates is not a reliable method to estimate emission factors.

Of the 21 plants, only three had production levels in excess of 364 Mg/d (400 tons/d) and 14 plants had levels between 182-364 Mg/d (200-400 tons/d). Test data for the uncontrolled emissions from the end box ventilation system were obtained from the same plant in three different years (1973, 1974, 1977). The data showed approximately an order of magnitude difference in

TABLE 5-2. MERCURY EMISSION RATES FOR CHLOR-ALKALI PRODUCTION FACILITIES

Emission source	Controls	No of plants	No of tests ^a	Emission rate, g/d (lb/d)			
				Range		Average	
End box ventilation system	Uncontrolled	1	3	23-163	(0.05-0.36)	100	(0.22)
	Scrubber	5	8	3-549	(0.006-1.21)	200	(0.44)
	Cooler/chiller	8	9	1-390	(0.003-0.86)	136	(0.30)
	Scrubber & cooler	2	2	2-426	(0.004-0.94)	213	(0.47)
	Scrubber & carbon adsorber	1	6	5-118	(0.01-0.26)	32	(0.07)
Hydrogen gas stream	Scrubber	1	2	86-236	(0.19-0.52)	163	(0.36)
	Cooler/chiller	8	14	1-689	(0.002-1.52)	308	(0.68)
	Cooler & carbon adsorber	4	12	9-159	(0.02-0.35)	73	(0.16)
	Cooler & molecular sieve	4	8	5-295	(0.01-0.65)	95	(0.21)
	Cooler & scrubber	1	1	59	(0.13)	59	(0.13)
	Cooler & molecular sieve & carbon adsorber	1	1	263	(0.58)	263	(0.58)

^aNumber of tests at each facility ranged from one to seven.

Source: Reference 14.

emission rates over the three test years. In 1973, the mercury emission rate was 163 g/d (0.36 lb/d) whereas in 1977, the emission rate was 23 g/d (0.05 lb/d). No test data were reported for uncontrolled emissions from the hydrogen gas stream.

The controlled emission rate data often showed a wide variability depending upon the emission control measure and the number of plants tested. In the end box ventilation system tests, the data presented for the scrubber were affected by a high emission rate from one facility, which had only one set of tests. The cited production level for this plant was the lowest of all plants tested (100 tons/day) so the high value is not a function of the production level. For the control system using a cooler followed by a scrubber, one of the two facilities showed a much higher emission rate (over 2 orders of magnitude) compared to the other facility. The plant with the higher emission rate had a lower stated production level (220 tons/d vs. 125 tons/d). In the hydrogen gas stream tests, the control measure consisting of a cooler, chiller, refrigerated cooler, or other gas cooling device, showed a three order of magnitude difference in emission rates among the eight facilities tested. The facility with the highest emission rate had a stated production level of 205 Mg/d (225 tons/d) whereas the facility with the lowest emission rate had a production level of 273 Mg/d (300 tons/d). The very large difference in emission rates is obviously not a function of the stated production levels.

Extreme caution should be exercised in the use of these rates for specific types of control devices at current mercury cell production facilities primarily because of the very wide variability in the emission rates between the plants. This wide variation does not appear to be a function of production levels at the plants. Differences between plants in the operation of the control devices may be a possible explanation. No evaluation of the variability in the data were presented in the EPA report.¹⁴ A second consideration is that the control techniques

at the current facilities may be considerably different from the techniques employed during these tests. In addition, even if the general technique (e.g., scrubbers, carbon adsorption) at the current facility is the same, considerable improvements in control efficiency may have been made since these tests were conducted. Recent test data and information on control measure system design and efficiency should be used to evaluate any current production facility.

5.2 BATTERY MANUFACTURING

Prior to the late 1980's, most primary batteries and some storage batteries contained mercury in the form of mercuric oxide (HgO), zinc amalgam (Zn-Hg), mercuric chloride (HgCl_2), or mercurous chloride (Hg_2Cl_2). Table 5-3 presents a synopsis of the three main types of primary batteries and their composition.

TABLE 5-3. MERCURY-CONTAINING BATTERIES

Cell type	Cathode	Anode	Electrolyte
HgO-Zn	1. HgO/MnO_2 2. HgO	Zn-Hg (amalgam)	Aqueous KOH or NaOH
Alkaline-Manganese batteries	MnO_2	Zn-Hg	Aqueous KOH
Leclanche' or zinc-carbon batteries	MnO_2 (10-30 wt. % acetylene black)	Zn-container (Prior to 1991, amalgamated with HgCl_2 or Hg_2Cl_2 to minimize corrosion and H_2 evolution)	NH_4Cl , ZnCl_2 , H_2O . Prior to 1991, the paste or solution applied to the paper separator contained HgCl_2 or Hg_2Cl_2

Source: References 14 and 20.

Since 1989, the use of mercury in primary batteries has decreased from 250 Mg (275 tons) in 1989 to 78 Mg (86 tons) in 1991 (see Table 3-2) and probably has decreased further in 1992. The primary decrease in usage has occurred with the alkaline-manganese batteries and the zinc-carbon batteries. The

production processes underwent an obvious change during this period to accommodate the new type of reduced mercury content batteries. The ensuing subsections discuss each of the three major types of batteries.

Operations at several battery manufacturing plants were investigated in 1983 via contacts with State agencies, industry, and site visits. Of these plants, five manufactured mercuric oxide-zinc or mercuric oxide-cadmium batteries; seven plants manufactured alkaline manganese batteries; and seven manufactured Leclanche' zinc-carbon batteries but the identify of specific plants was not disclosed.¹⁴ Table 5-4 presents the U.S. manufacturers and production sites for mercuric oxide, alkaline manganese, or zinc-carbon batteries in 1992.

5.2.1 Mercuric Oxide Batteries

Mercuric oxide batteries are small circular, relatively flat batteries that are used in transistorized equipment, walkie-talkie's, photoelectric exposure devices, hearing aids, electronic watches, cardiac pacemakers, and other items requiring small batteries. Of the three major types of batteries, only this type still adds mercury (mercuric oxide) as of the end of 1992.

Process Description--

The basic flow diagram for the manufacture of mercuric oxide batteries is shown in Figure 5-2. The mercuric oxide-zinc cells use mercuric oxide (mixed with graphite and manganese dioxide) as the cathode. The anode is a zinc-mercury amalgam.

In the production of the cathodes, mercuric oxide (Stream A), manganese dioxide (Stream B), and graphite (Stream C) are manually metered through a hopper to the blending area.¹⁴ The resulting mixture (Stream D) is sent to a processing unit where it is compacted into tablets by "slugging" (compression in

TABLE 5-4. MERCURIC OXIDE, ALKALINE MANGANESE, OR ZINC-CARBON BATTERY
MANUFACTURERS IN 1992

Manufacturer	Production site
Alexander Manufacturing Company (AMC, Inc.)	Mason City, IA
Duracell, USA	Cleveland, TN LaGrange, GA Lancaster, SC Lexington, NC
Eagle-Picher Industries, Inc.	Colorado Springs, CO
Eveready Battery Company, Inc.	Maryville, MO Red Oak, IA Fremont, OH Bennington, VT Asheboro, NC (2 plants)
Mutec ^a	Columbus, GA (Corporate offices)
Rayovac Corp.	Madison, WI Fennimore, WI Portage, WI

Source: Reference 5 and information provided by the National Electrical Manufacturers Association (NEMA).

^aMutec is a joint venture between Eastman Kodak and Panasonic.

ANODE
(MERCURIC OXIDE--ZINC CELLS)

● DENOTES POTENTIAL MERCURY EMISSION SOURCE

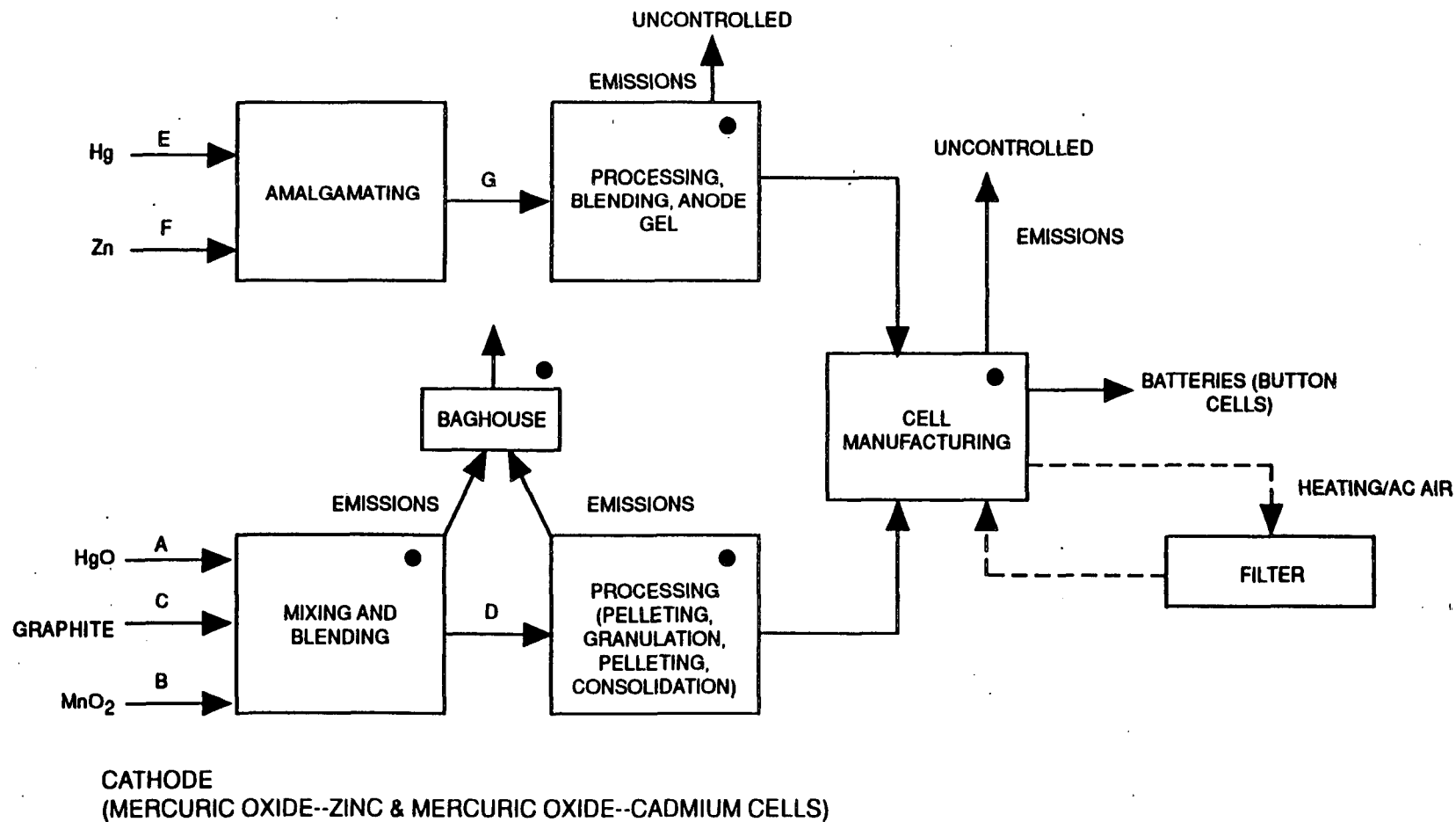


Figure 5-2. General flow diagram for mercuric oxide battery (button cell) manufacture. 14

a rotary pressing device to a specified density). These tablets are then granulated into uniformly sized particles, and then pelletized in a rotary press. The pellets are consolidated into small metal cans less than 1.3 cm (0.5 in.) in diameter.¹⁵

For the production of the anodes, elemental mercury (Stream E) and zinc powder (Stream F) are metered from hoppers or hold tanks into an enclosed blender to produce a zinc-mercury amalgam.¹⁵ The amalgam (Stream G) is sent to a processing area where it is blended and the anode gel formed.

The completed anodes and cathodes are then sent to the cell manufacturing area. Separators, electrolyte, and other components are assembled with the anode and cathode to produce the HgO-Zn cell. Assembly may be automatic or semiautomatic. The assembled cathode, anode, electrolyte, and cover are sealed with a crimper. Depending on the design, other components may be added. Those additional components may include an insulator, an absorber, and a barrier.

An integrated mercuric oxide battery plant may also produce HgO and recycled mercury onsite. Mercuric oxide production was discussed in Section 4 under mercury compound production. Secondary recovery of mercury at the battery plant was discussed in Section 4 under secondary mercury production.

Emission Control Measures--

Baghouses are used to control particulate emissions from the mixing/blending and processing steps in the production of cathodes. Mercury vapor emissions from the anode processing and cell manufacturing areas are generally discharged to the atmosphere uncontrolled. Ventilation air in the assembly room is recirculated through particulate filters. One plant reported an average of 73 percent mercury vapor removal efficiency in the cell assembly room when an air handler system, consisting of a

particulate prefilter and a charcoal filter, was operated using 75 percent recirculating air and 25 percent fresh air.¹⁵

In addition to the emission control measures, other methods can be used to reduce potential worker exposure in the workplace. Table 5-5 summarizes the types of methods used in the workplace to reduce worker exposure to mercury vapor and particulate during battery manufacturing.

Reject materials such as anodes, cathodes, chemical mixes, and cells can be stored under water to suppress mercury vaporization.¹⁵

Machinery for grinding, mixing, screening, pelletizing, and/or consolidating can be enclosed with little or no need for worker access. Two mercuric oxide button cell manufacturers in 1983 were using such enclosures and glove boxes to reduce worker exposure. Iris ports allowed access to the enclosed equipment. Exhaust airstreams are generally ducted to a baghouse. These facilities also used ventilated enclosures to store completed anodes and cathodes on the cell assembly lines; the exhaust air takeoffs from these enclosures led to a baghouse.¹⁵

Emissions--

During the manufacture of mercuric oxide batteries, mercury may potentially be emitted from several processes as particulate and as vapor emissions. These release points are indicated in Figure 5-2 by a solid circle. The processes include grinding, mixing, sieving, pelleting, and/or consolidating.

The only reported emission factor for a mercuric oxide production facility was for one plant in Wisconsin.¹⁹ This facility used a combination of a baghouse and charcoal filter to treat the exhaust ventilation air. Annual use of mercury was 36.17 Mg (39.8 tons) and annual emissions were reported as 36.3 kg (80 lb) of mercury as HgO particles. For this specific

**TABLE 5-5. METHODS FOR REDUCING WORKER EXPOSURE TO MERCURY
EMISSIONS IN BATTERY MANUFACTURING**

Control methods	Particulate	Vapor
Process modification and substitution	χ^a	
Contaminant	χ^a	$\chi^{d,e}$
Ventilated enclosure	$\chi^{b,c}$	$\chi^{d,e}$
Local exhaust ventilation	$\chi^{a,b,c}$	$\chi^{d,e}$
Temperature control		$\chi^{d,e}$
Dilution ventilation	$\chi^{a,b,c}$	$\chi^{d,e}$
Isolation	$\chi^{a,c}$	$\chi^{d,e}$
Mercury removal from air stream	$\chi^{a,b,c}$	
Personal protective equipment	$\chi^{a,b}$	

^aParticulate emissions during loading of mixers and blenders in cathode preparation.

^bParticulate emissions from grinding, slugging, and pelletizing in cathode production.

^cParticulate emissions from drying, screening, and pelletizing in anode production.

^dVapor emissions from blending, drying, and pelletizing during anode production.

^eVapor emission from product components.

Source: Reference 15.

facility, the mercury emission factor would be 1.0 kg/Mg (2.0 lb/ton) of mercury used.¹⁹ No mercury emissions were reported for this facility in the 1990 TRI.⁵

This emission factor should be used with extreme caution for several reasons. The data, both usage and emissions, are over 10 years old and emission controls may have changed in the interim. Although it is not specifically stated in Reference 19, it is also presumed that the mercury emission quantity is an estimate by the manufacturer because no reference is made to any emissions testing performed at the facility. Moreover, this factor is for one year at one specific site so that extrapolation of this factor to all mercuric oxide battery manufacturing facilities can lead to erroneous results.

Based on another study, the emission source rates from an integrated mercury button cell plant are summarized in Table 5-6.¹⁴ Data reported for this facility also included the HgO production plant and the mercury recovery plant, but these data were deleted from this table because they are addressed in Section 4. Major emission points were the pelleting and consolidating operations (up to 42 g/d; 0.094 lb/d) and cell assembly (29 g/d; 0.063 lb/d). Emission controls were not in place for mercury vapor emissions from the main plant.¹⁴ This plant reported total mercury emissions of 3.2 kg (7 lb) in the 1990 TRI.⁵

Other HgO battery plants in 1983 consumed up to 25 percent as much mercury as the integrated HgO plant and emitted 2 to <200 g Hg/d (0.003 to <0.4 lb/d). Baghouses and charcoal filters were the primary measures used to control emissions.¹⁴

5.2.2 Alkaline-Manganese Batteries

The alkaline-manganese battery uses essentially the same electrode materials as the Leclanche' system described in the

**TABLE 5-6. EMISSION SOURCE PARAMETERS FOR AN INTEGRATED
MERCURY BUTTON CELL MANUFACTURING FACILITY**

	Emission rate ^b		
Building/source no. description ^a	g/d	lb/d	Exit temp., °K, and control device
Main Plant			
Control Room			
1. Blending, slugging, compacting, granulating	6.12	0.0135	297; Baghouse
2. Slugging, granulating	1.22	0.0027	297; Baghouse
3. Pelleting, consolidating	1.63 ^c	0.0036 ^c	295; Baghouse
4. Pelleting, consolidating	42.46	0.0936	297; Baghouse
4a. Pelleting, consolidating	6.53	0.0144	297; Baghouse
5. Blending, compacting, granulating, pelleting, consolidating	1.36 ^c	0.003 ^a	297; Baghouse
Anode room			
6. Amalgam, dewatering	1.82 ^c	0.004 ^c	297; Uncontrolled
6a. Vacuum dryer	0.46 ^c	0.001 ^c	297; Uncontrolled
6b. Blending	0.91 ^c	0.002 ^c	297; Uncontrolled
7. Pelleting, zinc amalgam	4.08 ^c	0.009 ^c	295; Baghouse
Cell assembly area			
8. Assembling calls	28.58	0.0630	295; Baghouse for particulate. Vapor by recirculating air through prefilters and charcoal filters

^aSource numbers are the same code used by facility.

^bEmission rates were measured by facility except where noted.

^cEstimated emission rate by facility.

Source: Reference 14.

next subsection; the only difference is the electrolyte. This battery is characterized by good low temperature performance and a long shelf life. Alkaline-manganese batteries are used in movie cameras, electronic flash devices, tape recorders, toys, shavers, and other devices resulting in a heavy-discharge use. The use of mercury in this battery system has decreased considerably since 1989, and it is anticipated that little, if any, mercury will be used by the end of 1993. Two of the major alkaline-manganese battery manufacturers ceased adding mercury to the batteries in 1992 and the other two major companies will cease by the end of 1993.

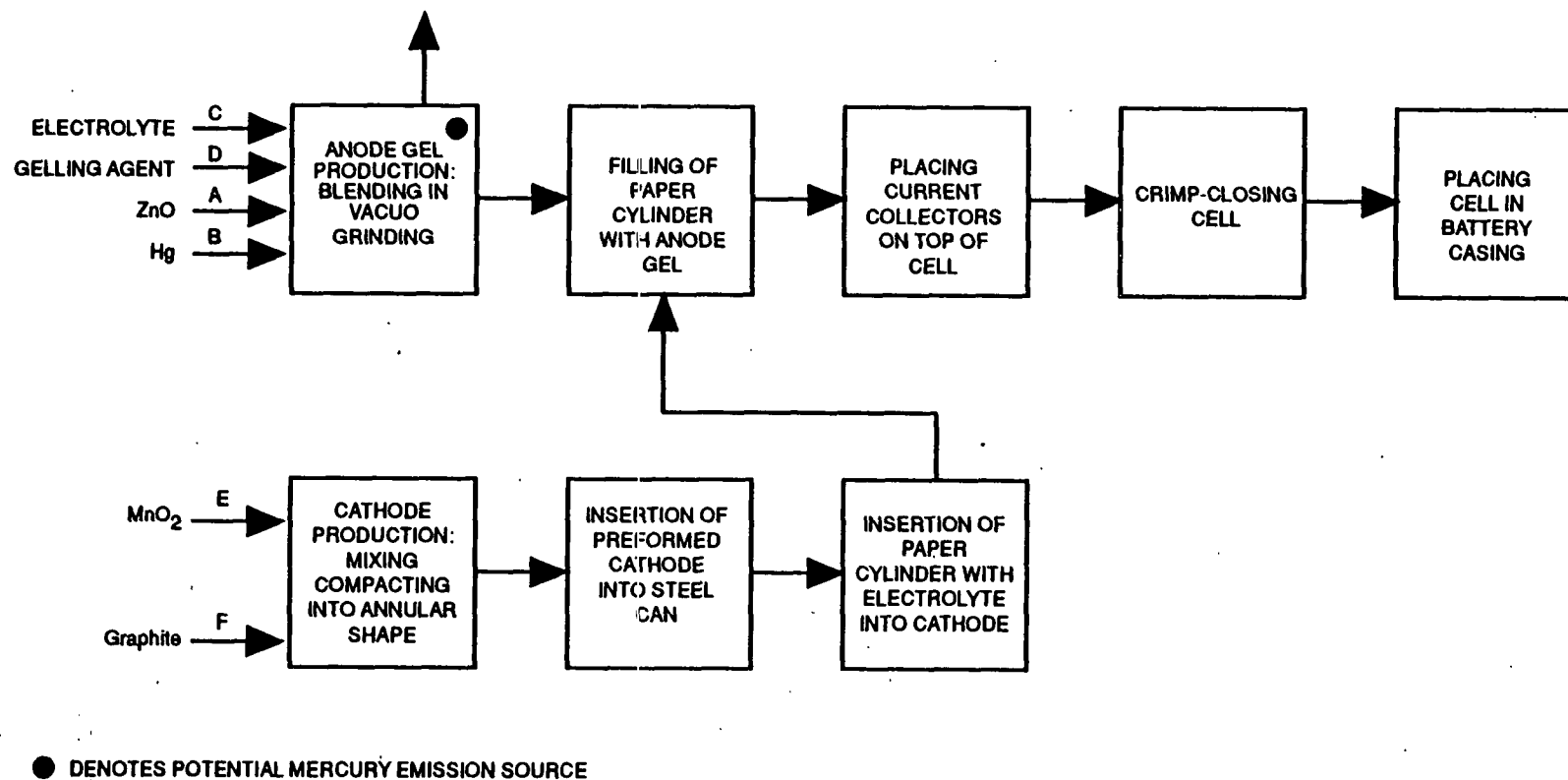
Process description¹⁵--

The process flow diagram for alkaline cell manufacture is given in Figure 5-3. For the production of the anodes, zinc oxide (Stream A), elemental mercury (Stream B), the electrolyte solution (Stream C), and a gelling agent (Stream D) are mixed in an enclosed blender to produce an anode gel. The gel is held for a specified time and then fed manually into a grinder to remove any lumps before transport, in sealed plastic cans, to the cell assembly area.

The cathode is formed by compacting a mixture of manganese dioxide (MnO_2) (Stream E) and graphite (Stream F) into an annular shape. During cell assembly, the preformed cathode is injected into a steel can and a paper cylinder is inserted into the cathode together with the electrolyte. The inner cylinder is filled manually or automatically with the anode gel. The final battery is produced by placing current collectors on top of the cell, crimp-closing the can, and placing the cell in a battery casing.

Emission Control Measures--

Baghouses are generally used to control particulate emissions, particularly from the cell assembly areas, but mercury vapor emissions are uncontrolled.

Figure 5-3. Alkaline cell manufacture.¹⁵

Emissions--

During the production of alkaline-manganese batteries, mercury may be emitted primarily from the anode gel production area as denoted on Figure 5-3 by a solid circle. The only reported emissions data are for an alkaline-manganese battery production facility in Wisconsin.¹⁹ At this facility, mercury vapor from the blender in the gel production area was passed through charcoal filters prior to discharge; no other control measures were stated for other production areas. Annual use of mercury was 33.0 Mg (36.4 tons) and annual air emissions from the facility were reported to be 0.9 kg (2 lb) of mercury. The mercury emission factor for this facility would be 0.03 kg/Mg (0.05 lb/ton) of mercury used. This facility reported annual emissions of 4.5 kg (10 lb) in the 1990 TRI.⁵

This emission factor should be used with extreme caution because of several reasons. The data, both usage and emissions, are over 10 years old and emission controls may have changed in the interim. Although it is not specifically stated in reference 19, it is also presumed that the mercury emission quantity is an estimate by the manufacturer because no reference is made to any emissions testing performed at the facility. Moreover, this factor applies to a given year at a specific site, and extrapolation of this factor to other alkaline-manganese production facilities can lead to erroneous results.

5.2.3 Leclanche' Zinc-Carbon Batteries

The Leclanche' cell or zinc-carbon battery has been a major factor in the primary battery market since its introduction in the 1860's. Prior to 1989, the dry cells used a cathode of manganese dioxide, and acetylene black, and an anode of zinc. There are two general categories for the dry cell: round and flat, but the difference is primarily physical, not chemical. The popularity of these dry cells is due in part to their relatively low cost, availability in many voltages and sizes, and

suitability for intermittent and light-to-medium current drainage uses. Zinc-carbon batteries find extensive use in numerous commercial products.²⁰⁻²² Like the alkaline-manganese battery, the use of mercury in this battery system has decreased since 1989. It is doubtful that any mercury was still in use by the end of 1992 for the production of zinc-carbon batteries.

Process Description--

The overall process for the manufacture of zinc-carbon batteries did not change significantly with the removal of mercury from the process. In these batteries, the mercury was present to retard detrimental side reactions in the cell, to increase shelf life, and as a corrosion inhibitor; mercury was not an integral part of the cell reaction. It was the development of alternative methods and materials that led to the removal of mercury from these batteries. The primary detrimental effect in these batteries is side reactions and the leakage of air into the battery cell; air dries out the cell medium (a paste or moist paper separator) and provides the oxygen necessary for corrosion of the battery container which results in gas formation. Three major improvements were made in the battery construction:

1. Improved integrity of the seals of the battery;
2. Quality of the raw materials; and
3. Development of nonmercury inhibitors.

The improved integrity of the seals in the battery containers led to a significant reduction in air leakage into the battery and reduced gas formation. Requirements for higher purity raw materials resulted in fewer detrimental side reactions that would affect the battery integrity. Finally, the development of effective nonmercury corrosion inhibitors made the use of mercury unnecessary. The chemical nature of these corrosion inhibitors is highly proprietary with each company so no information can be provided regarding their chemical structure or type.

The removal of mercury from the production of zinc-carbon batteries negates the need for any discussion of the emission control measures for mercury as well as any discussion of mercury emissions during the production process. Therefore, no further discussion of zinc-carbon batteries is presented.

5.3 ELECTRICAL USES

Because mercury is rated as one of the best electrical conductors among the metals, it is used in many electrical applications including electric switches, electric lamps, thermal sensing elements, and other electrical uses.

5.3.1 Electric Switches

The primary use of elemental mercury is for silent electric wall switches and electric switches for thermostats. The mercury "buttons" used in wall switches consist of mercury, metal electrodes (contacts), and an insulator. The thermostat switches are constructed of a short glass tube with wire contacts sealed in one end of the tube. An outside mechanical force or gravity activate the switch by causing the mercury to flow from one end of the tube to the other, thus providing a conduit for electrical flow.

The National Electrical Manufacturers Association (NEMA) was contacted for manufacturers of electric switches that may contain mercury in the devices. The fifteen companies identified by NEMA were contacted to determine whether mercury was used at any of their production facilities. Of the fifteen companies, seven stated that no mercury was used at their production facilities. General Electric Corporation stated that thermostats, both with and without mercury, were produced at their Morrison, Illinois facility. Honeywell, Inc. produces microswitches that contain mercury at their Freeport, Illinois facility. The six companies shown below either declined to provide any information or

provided a response for only a portion of their divisions and declined to comment on the other divisions.

<u>Company</u>	<u>Corporate Headquarters</u>
Eaton Corporation	Cleveland, OH
Emerson Electric Co.	St. Louis, MO
Johnson Controls, Inc.	Milwaukee, WI
Ranco, Inc.	Plain City, OH
Therm-O-Disc	Mansfield, OH
United Technologies	Huntington, IN

Process Description--

Mercury Buttons for Wall Switches¹⁵--The manufacture of mercury buttons for wall switches is shown in Figure 5-4. In this process, a metal ring, glass preform, ceramic center, and center contact are assembled on a semiautomatic loader (Step 1) and fused together in a sealing furnace (Step 2). Each subassembly is then transferred to a rotating multistation welding machine, which is completely enclosed, where the subassembly is filled with about 3 g (0.11 ounces) of mercury (Step 3). The mercury used to fill the subassembly is stored in an external container. During the subassembly filling step, the mercury container is pressurized with helium; this pressurization transfers the mercury from the large storage container to a smaller holding tank. Mercury is released in a controlled manner from the holding tank by using a rotating slide gate that is synchronized to the welding machine speed. The filled subassembly is manually placed in the can, evacuated, and welded shut to form the button (Step 4).

After leaving the isolation room, the buttons are cleaned (Step 5), zinc plated (Step 6), and assembled with other components (Step 7) to form the finished wall switches.

Thermostat Switches--The production process for thermostat switches used for household heating/air conditioning control and other applications is shown in Figure 5-5. Metal electrodes

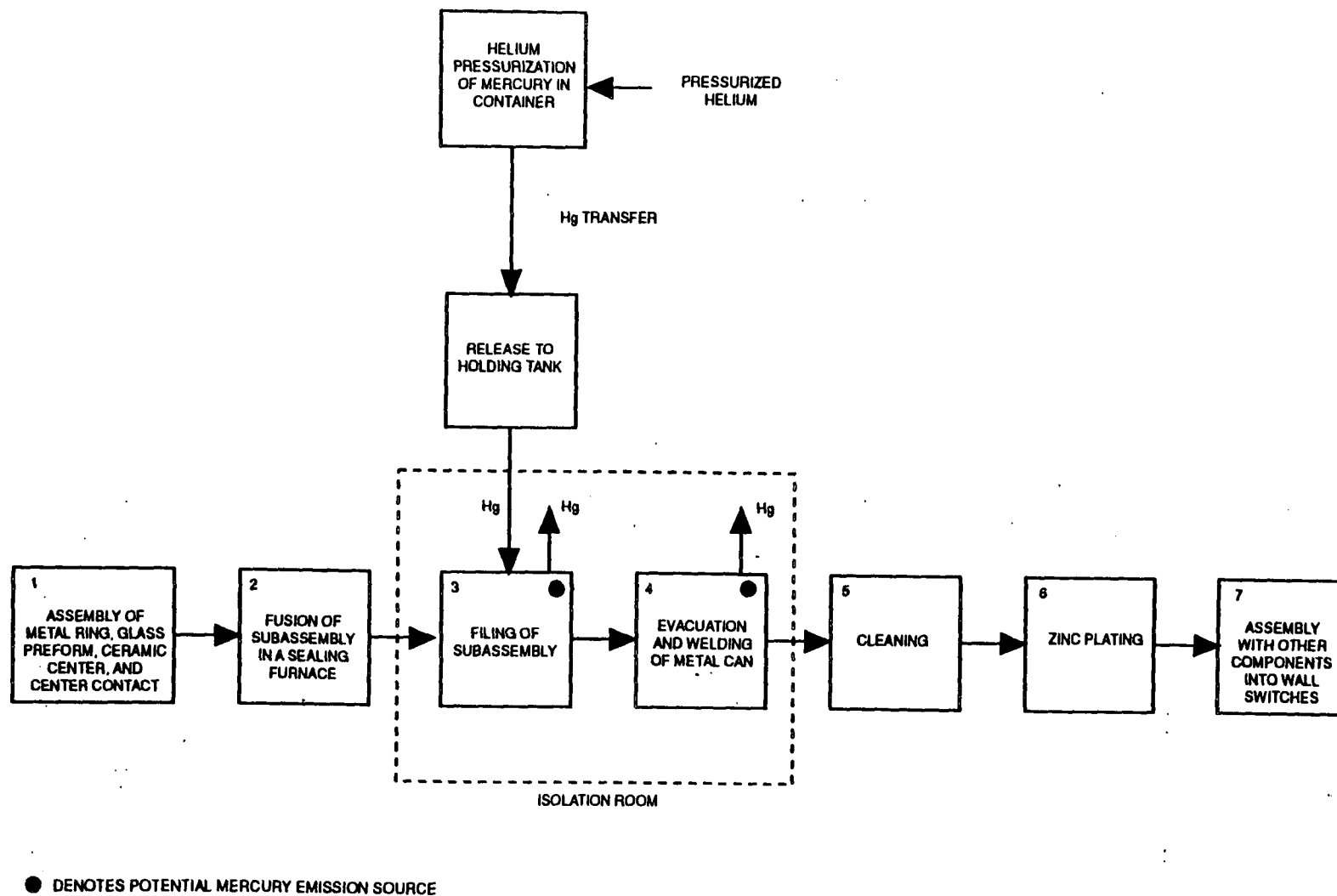


Figure 5-4. Manufacture of mercury buttons for wall switches. 15

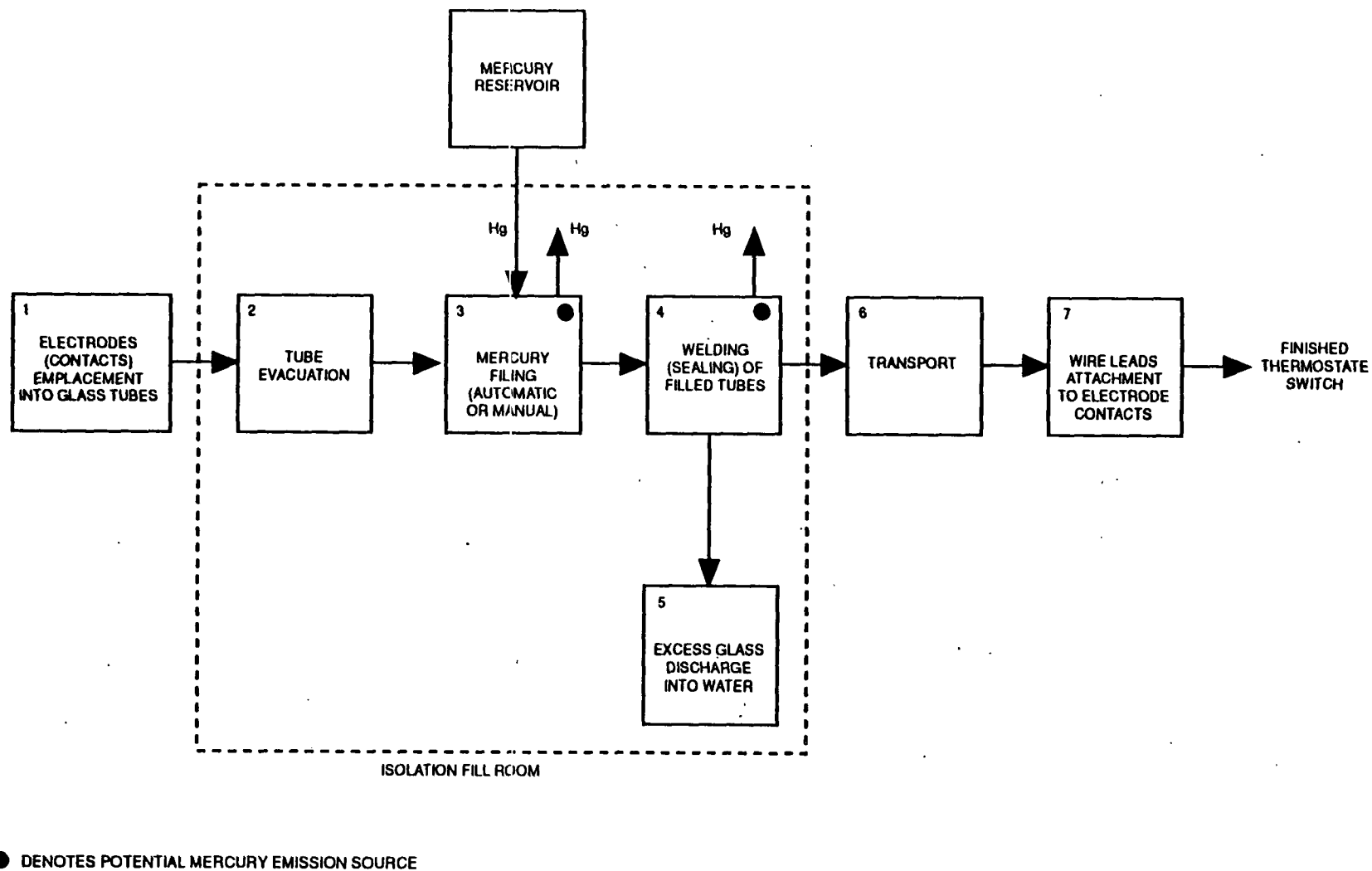


Figure 5-5. Thermostat switch manufacture.¹⁵

(contacts) are inserted into one end of a glass tube 0.89 to 1.5 cm (0.35 to 0.59 in.) in diameter (Step 1). This end of the tube is then heated, crimped around the electrodes, and then sealed. The apparatus is then cleaned, transferred to the isolation fill room, and loaded onto the filling machine where the tubes are evacuated (Step 2). At the filling machine (Step 3), the vacuum in the glass tube is released and mercury is drawn into the tube. The open end of the mercury-filled tube is heated, constricted, and sealed (Step 4). Filling of switch tubes produced in low volume is performed manually using the same sequence of steps. Excess glass at the seal is discarded into a bucket of water (Step 5). The filled tube leaves the isolation room and falls into a transport container (Step 6). Attachment of wire leads to the electrode contacts completes the switch assembly (Step 7).

Emission Control Measures¹⁵--

Table 5-7 shows typical emission control methods used in the mercury switch industry to reduce worker exposure to mercury vapor.

The use of isolation rooms and automated systems for fill operations in the manufacture of mercury buttons has reduced considerably the manual handling of elemental mercury. For example, a mercury refiner supplies 363 kg (800 lb) of mercury in stainless steel storage containers that are individually mounted in steel frames to permit lifting and transport by forklift. The alternative procedure is to manually transfer the mercury from 76-lb iron flasks to the holding tank.

The use of effective gaskets and seals allows containment of mercury in the process streams. Reject and broken switches are discarded under water to suppress mercury vaporization.

Exhaust ventilation, which is custom designed to fit specific equipment, is often used to reduce worker exposure to

TABLE 5-7. MEASURES TO REDUCE WORKPLACE EXPOSURE TO MERCURY
VAPOR EMISSIONS IN THE ELECTRIC SWITCH INDUSTRY

Control method	Sources			
	Hg purification and transfer	Hg filling	Product testing	Spills, breakage, rejects
Process modification and substitution	X			
Containment	X			X
Ventilated enclosure			X	
Local exhaust ventilation	X	X	X	X
Temperature control	X	X	X	X
Dilution ventilation	X	X	X	X
Isolation	X			

Source: Reference 15.

mercury vapor, mercury particulate, or both. For example, a specially designed circular slot hood may be used to cover the filling and welding machine. Plastic strip curtains may be suspended from the hood to help prevent airflow from the hood into the work room.

Temperature control is widely practiced as one of the most effective measures to reduce mercury emissions. Reducing the fill room temperature to between 18° and 20°C (64° and 68°F) can be effective in lowering mercury emissions. Some industry operations shut down and require personnel evacuation from the room when temperatures rise above 21°C (70°).

Dilution ventilation of fill room air, without apparent control, has been practiced at mercury switch plants. The negative pressure in the fill room prevents escape of mercury vapor into adjacent assembly areas.

Examples of technology for removing mercury from exhaust streams were not found. However, controls used at other manufacturers of electrical and electronic items may be effective at mercury switch plants. These controls are discussed in subsequent subsections.

Emissions--

During the manufacture of electric switches (wall and thermostat), mercury may potentially be emitted during welding or filling, as a result of spills or breakage, during product testing, and as a result of material transfer. The mercury emission sources are indicated in Figures 5-4 and 5-5 by a solid circle.

Table 5-8 lists the five manufacturers of electric switches that reported mercury air emissions in the 1990 Toxics Release Inventory.⁵ Total reported emissions from these manufacturers was 14 pounds.

No mercury emission data have been published for other manufacturers of electrical switches. In the production of either mercury buttons for wall switches or thermostat switches, the principal sources of mercury emissions occur during filling processes that are conducted in isolated rooms. The isolation rooms are vented to maintain the room at a slight negative pressure and prevent mercury contamination of adjacent work areas. However, no emission data or results of tests are available to develop an estimate of mercury emissions from these two processes.

5.3.2 Thermal Sensing Elements¹⁵

In certain temperature-sensing instruments, a bulb and capillary temperature-sensing device is an integral part of the instrument. These devices use the expansion force of mercury as

**TABLE 5-8. MANUFACTURERS OF ELECTRIC SWITCHES AND ELECTRONIC COMPONENTS
REPORTING IN THE 1990 TOXICS RELEASE INVENTORY**

Facility	Location	Comments	Total annual air emissions, lb
Babcock Display Products	Anaheim, CA	Gas discharge display; Hg used as a formulation component and possibly recycled	0
Durakool, Inc.	1010 N. Main Street Elkhart, IN	Repackaging only	5
Emerson Puerto Rico Inc.	Dorado, PR	Switch gear and switchboard apparatus Hg used for "ancillary or other use"	0
Hermaseal Co.	1101 Lafayette Elkhart, IN	Repackaging only	5
Micro Switch Honeywell Div.	Freeport, IL	Hg used as an article component	4

Source: Reference 5.

it is heated to activate the external controls and indicators of the instrument.

Process Description--

A thermal sensing instrument consists of a temperature-sensing bulb, a capillary tube, a mercury reservoir, and a spring loaded piston. The bulb is made by cutting metal tubing to the correct size, welding a plug to one end of the tube, and attaching a coupling piece to the other end. The capillary tube is cut to a specified length and welded to the coupling at the open end of the bulb. The other end of the capillary is welded to a "head" that houses the mechanical section of the sensor.

The bulb and capillary assembly are filled with mercury by a multistation mercury filling machine that is housed in a ventilated enclosure. After filling, the sensor is transferred to a final assembly station where a return spring and plunger are set into a temporary housing on the head of the sensor. To complete the temperature instrument, the sensor is then attached to a controller and/or indicating device.

Emission Control Measures--

No information was found on specific emission control devices or measures to control mercury emissions during the filling process. Although the filling machine is typically in a ventilated enclosure, no information is available concerning any subsequent treatment of the exhaust gas prior to discharge to the atmosphere.

Emissions--

No emission factors for mercury emissions from thermal sensing element manufacturing were found in the literature, and no emission test data were available to calculate emission factors.

5.3.3 Tungsten Bar Sintering¹⁵

Process Description--

Tungsten is used as a raw material in the manufacture of incandescent lamp filaments. The manufacturing process starts with tungsten powder pressed into long, thin bars of a specified weight. These bars are pretreated and then sintered using a high-amperage electrical current. During the tungsten bar sintering process, mercury is used as a continuous electrical contact. The mercury contact is contained in pools (mercury cups) located inside the sintering unit.

After the sintering process is completed, the bars are cooled to ambient temperature to determine the density of the tungsten bar. Metallic mercury is normally used in these measurements because of its high specific gravity. To calculate the density of the tungsten bar, the bars are dipped into a pool of mercury, and the weight of the displaced mercury is determined. When the bar is removed from the mercury pool, the mercury is brushed off into a tray of water that is placed in front of the pool.

Emission Control Measures--

No specific information on emission control measures for sintering tungsten bars was found in the literature.

Emissions--

Mercury is used only during the actual sintering and the final density measurements. For this reason, it is assumed that these two operations account for all the mercury emitted from the process. No specific data for mercury emissions from the tungsten sintering process were found in the literature, and no emission test data were available to calculate mercury emission factors.

5.3.4 Copper Foil Production¹⁵

High purity copper foil, used as a laminate in printed circuit boards, is produced by an electrodeposition process using mercury as the electrical contacts.

Process Description--

The initial step in the foil production process is the dissolution of scrap copper in sulfuric acid to form copper sulfate. The solution is then fed to the plating operation where the copper ions are electrodeposited on rotating drums as copper metal. Each plating drum is composed of a concrete cell containing the copper sulfate solution, an anode (lead), a rotating titanium drum (cathode), and a winding roll. During the electrodeposition process, a current passes between the lead anode and the rotating drum cathode. As the drum rotates, the copper metal is electrodeposited on the drum surface in the form of a continuous thin foil sheet.

Elemental mercury is used as the continuous contact between the rotating shaft of the rotating drum and the electric connections. The liquid mercury is contained in a well located at one end of the rotating drum shaft.

Emission Control Measures--

Manufacturing processes that require mercury as an electrical contact generally use ventilated enclosures for controlling vapor emissions from mercury pools. In copper foil production, the mercury wells are located in ventilated enclosures, and exhaust gases are directed to a mercury vapor filter. Another method of controlling emissions from mercury wells is to reduce the temperature of mercury in the well. Generally, mercury wells operate at 82°C (180°F); at this temperature, mercury has a vapor pressure of 0.10 mmHg. A temperature reduction to 21°C (70°F) decreases the mercury vapor pressure to 0.0013 mmHg.

Emissions--

Mercury is emitted from the drum room and treatment room of the copper plating process. No information was available on mercury release rates to the atmosphere through ventilation systems. No specific data for mercury emissions from the production of copper foil were found in the literature, and no emission test data were available for calculating emission factors.

5.3.5 Fluorescent Lamp Manufacture¹⁵

Information obtained from NEMA indicates that there were four fluorescent lamp manufacturers in the U.S. in 1992. The names and production facility locations are presented in Table 5-9.

TABLE 5-9. FLUORESCENT LAMP MANUFACTURING

Company	Plant Location	Comments
Duro-Test Corp.	North Bergen, NJ	Division Headquarters; Declined to identify production facility locations
General Electric	Bucyrus, OH	Standard fluorescent lamps
	Circleville, OH	Standard fluorescent lamps
Osram/Sylvania, Inc.	Danvers, MA	Standard fluorescent lamps
	Manchester, NH	HID (high intensity discharge) lamps
	Versailles, KY	HID lamps and standard fluorescent lamps
Philips Lighting Co.	Fairmont, WV	Ultraviolet and germicidal lamps
	Salina, KS	Standard fluorescent lamps
	Bath, NY	Mercury vapor lamps and HID lamps

Process Description--

Fluorescent lamp production begins with the preparation of the lamp tube. Precut glass tubes are washed to remove impurities, dried with hot air, and coated with a liquid phosphor emulsion that deposits a film on the inside of the lamp tube. Mount assemblies, consisting of a short length of glass exhaust tube, lead wires, and a cathode wire, are fused to each end of

the glass lamp tube. The glass lamp tube, with attached mount assemblies, is then transferred to the exhaust machine.

On the exhaust machine, the entire glass tube system is exhausted and a small amount ($15 - 250 \text{ mg}/3.3 \times 10^{-5} - 5.5 \times 10^{-4} \text{ lb}$) of mercury is added, which adheres to the emulsion coating on the interior of the glass lamp tube. Following the addition of mercury, a vacuum is drawn through the exhaust tubes to remove excess mercury and evacuate the glass lamp tube system. The glass tube system is then filled with inert gas and sealed. After the lamp tubes are sealed, metal bases are attached to the ends of the lamp tube and are cemented in place by heating.

Emission Control Measures--

No emission control measures were identified for exhaust or ventilation gases. The only methods identified were those used to reduce worker exposure. Mercury air concentrations due to handling are usually reduced by containment, local exhaust ventilation, temperature control, isolation, and/or mercury removal from the air stream. Mercury air levels during the lamp production steps are reduced by process modifications, containment, ventilated enclosures, local exhaust ventilation, and temperature control.

In 1991, 29 Mg (32 tons) of mercury were used to manufacture electric lamps, including fluorescent, mercury vapor, metal halide, and high-pressure sodium lamps. These lamps are used in street lights, high-ceiling rooms, film projectors, photography, dental exams, photochemistry, heat lamps, and water purification. In 1980, it was estimated that the amounts of mercury used for indoor and outdoor applications were equally divided.²³

Emissions--

Mercury emissions during fluorescent lamp manufacturing occur during mercury handling and lamp production. Mercury handling procedures result in vapor emission from mercury

purification, transfer, and parts repair. Lamp production results in mercury emissions from the injection operation and from broken lamps, spills, and waste material.

A 1984 emission rate of 10.2 g/d (0.02 lb/d) was found in NATICH (National Air Toxics Information Clearinghouse) for a GTE lamp manufacturing facility in Kentucky.²⁴ However, no information was available on the quantity of mercury used at the facility, the number of units produced, or other data that would permit a comparison of this emission rate with other facilities. In addition, no data were presented to allow calculation of an annual quantity. Only one lamp manufacturing facility (General Electric Company Bucyrus Lamp Plant) reported mercury emissions in the 1990 TRI; their annual emissions were 0.44 Mg/yr (0.48 tons/yr).⁵

About 50 percent of the mercury used to manufacture electric lamps is for outdoor applications. About one-third of this amount is lost to the atmosphere annually after the lamp is broken and about one-fifth of the amount used in indoor lamps is lost upon disposal.²³

5.4 INSTRUMENT MANUFACTURING AND USE (THERMOMETERS)

Mercury is used in many medical and industrial instruments for measurement and control functions including thermometers; manometers, barometers, and other pressure-sensing devices; gauges; valves; seals; and navigational devices. Because mercury has a uniform volume expansion over its entire liquid range and a high surface tension, it is extremely useful in the manufacture of a wide range of instruments. Process descriptions, emission control measures, and emissions are limited to a very few

instruments. One of those instruments is the thermometer and the ensuing discussion will focus on that instrument.

5.4.1 Process Description^{14,15}

The manufacture of temperature measurement instruments varies according to the type of bulb or probe. In addition, the mercury filling procedure varies among different instrument manufacturers. The production of glass thermometers begins with cutting glass tubes into required lengths. Next, the bulb used to contain mercury is attached to the tube; either glass or metal bulbs may be used.

The tubes are filled with mercury in an isolated room. A typical mercury filling process is conducted inside a bell jar. Each batch of tubes is set with open ends down into a pan and the pan set under the bell jar, which is lowered and sealed. The tubes are heated to approximately 200°C (390°F) and a vacuum is drawn inside the bell jar. Mercury is allowed to flow into the pan from either an enclosed mercury addition system or a manually filled reservoir. When the vacuum in the jar is released, the resultant air pressure forces the mercury into the bulbs and capillaries. After filling, the pan of tubes is manually removed from the bell jar. Excess mercury in the bottom of the pan is refiltered and used again in the process.

Excess mercury in the tube stems is forced out the open ends by heating the bulb ends of the tubes in a hot water or oil bath. The mercury column is shortened to a specific height by flame-heating the open ends (burning-off process). The tubes are cut to a finished length just above the mercury column, and the ends of the tubes are sealed. All of these operations are performed manually at various work stations. A temperature scale is etched onto the tube, completing the assembly.

5.4.2 Emission Control Measures

Several emissions control measures have been identified for production processes that require, in part, the filling of an apparatus with metallic mercury. In the previous discussion of the electric switch industry, Table 5-8 delineated several control methods that are used by that industry. To a large extent, these controls or combination of controls are generally applicable to the production of thermometers. Within the industry, vapor emission from mercury purification and transfer is typically controlled using containment procedures, local exhaust ventilation, temperature reduction to reduce the vapor pressure, dilution ventilation, or isolation of the operation from other work areas. The tube bore size can be modified to reduce the use of mercury. Other measures that may be applied are use of local exhaust ventilation, dilution ventilation, and temperature control.

The major source of mercury emissions in the production of thermometers may be in the mercury filling step. In this step, virtually all of the control measures identified in Table 5-8 would be applicable, to some degree. One of the latter steps in the production involves heating the mercury in a high temperature bath and the subsequent heating of the open ends with a flame (burning-off process). This stage of the production would be particularly amenable to a ventilated isolation room, using local exhaust ventilation in addition to dilution ventilation, to create a slight negative pressure in the room. This procedure would prevent escape of mercury vapor into adjacent assemble or work areas.

5.4.3 Emissions

Mercury emissions can occur from several sources during the production of thermometers. From the available information, many of the procedures used in the production are manual and, as a

result, it is more difficult to control the mercury emissions. The most prevalent sources of emissions result from three steps or stages in the process: (1) mercury purification and transfer, (2) the mercury filling process, and (3) the heating out/burning off steps. Vapor emission due to spills of mercury, broken thermometers, and other accidents can add to the level of emissions.

No specific data for mercury emissions from the manufacturer of thermometers were found in the literature, and no emission test data were available to permit the calculation of mercury emissions.

SECTION 6

EMISSIONS FROM COMBUSTION SOURCES

Mercury is often found as a trace contaminant in fossil fuels or waste materials. When these materials are fed to combustion processes, the combination of the elevated temperature of the process and the volatility of mercury and mercury compounds results in mercury being emitted in the combustion gas exhaust stream. This section addresses mercury and mercury compound emissions from seven stationary source combustion processes:

- Coal combustion
- Oil combustion
- Natural gas combustion
- Wood combustion
- Municipal waste combustion
- Sewage sludge incineration
- Medical waste incineration

These seven processes fall into two general categories. The first four involve fuel combustion for energy, steam, and heat generation, while the last three are primarily waste disposal processes, although some energy may be recovered from these processes. The paragraphs below provide a general introduction to the two combustion categories. As part of this introduction, a summary of nationwide fuel usage is presented in detail. This information was used in Section 3 to develop nationwide emissions of mercury for different sectors and fuels. It is included in the introduction rather than in individual sections because (1) the individual sections are organized by fuel type rather than by use sector and (2) fossil fuel use patterns differ

geographically and by industry sector. The introduction also briefly describes the waste combustion category. Specific discussions for the seven source categories follow these introductory paragraphs.

In 1990, the total annual nationwide energy consumption in the United States was 85.533×10^{12} megajoules (MJ) (81.151×10^{15} British thermal units [Btu]).²⁵ Of this total, about 52.011×10^{12} MJ (49.347×10^{15} Btu) or 61 percent involved consumption of coal, petroleum products, and natural gas in nontransportation combustion processes. (No data were available on energy consumption for wood combustion from the U.S. Department of Energy.) Table 6-1 summarizes the 1990 U.S. distribution of fossil fuel combustion as a function of fuel type in the utility, industrial, commercial, and residential sectors. The paragraphs below provide brief summaries of fuel use patterns; additional details on fuel consumption by sector for each State can be found in Reference 25.

As shown in Table 6-1, the utility sector is the largest fossil fuel energy consumer at the rate of 21.290×10^{12} MJ (20.199×10^{15} Btu) per year. About 80 percent of this energy was generated from coal combustion, with bituminous and lignite coal contributing substantially greater quantities than anthracite coal. In fact, Pennsylvania is the only State in which anthracite coal is used for electric power generation. Although most States rely primarily on coal for power generation, the distribution among fossil fuels varies from State to State, and several States rely heavily on natural gas and fuel oil for power generation. In California, natural gas provides about 90 percent of the fossil-fuel based electricity production, and no coal is used. In Hawaii, fuel oil is used exclusively, while in Oklahoma and Texas, a mixture of coal and natural gas are used. In Florida, Louisiana, Massachusetts, and New York, coal, fuel oil, and natural gas each represent a substantial fraction of the power generation. The States of Idaho, Maine, Rhode

TABLE 6-1. DISTRIBUTION OF FOSSIL FUEL CONSUMPTION
IN THE UNITED STATES

Fuel	Annual energy consumption 10 ¹² MJ (10 ¹⁵ Btu)				
	Utilities	Industrial	Commercial	Residential	Total
Bituminous/ lignite coal	16.939 (16.071)	2.892 (2.744)	0.085 (0.081)	0.045 (0.043)	19.961 (18.939)
Anthracite coal	0.018 (0.017)	0.010 (0.010)	0.013 (0.012)	0.019 (0.018)	0.060 (0.057)
Distillate oil	1.201 (1.139)	1.245 (1.181)	0.513 (0.487)	0.882 (0.837)	3.841 (3.644)
Residual oil	0.091 (0.086)	0.436 (0.414)	0.255 (0.242)	- -	0.782 (0.742)
Other petroleum fuels	0.026 (0.025)	7.083 (6.720)	0.197 (0.187)	0.452 (0.429)	7.758 (7.361)
Natural gas	3.015 (2.861)	8.925 (8.468)	2.907 (2.758)	4.762 (4.518)	19.609 (18.605)
Total	21.290 (20.199)	20.591 (19.537)	3.970 (3.767)	6.160 (5.845)	52.011 (49.347)

Source: Reference 25.

Island, and Vermont had no coal consumption. Idaho relies exclusively on hydroelectric power, while the New England States use a mixture of fuel oil, natural gas, nuclear, and hydroelectric power.

At 20.591×10^{12} MJ (19.537×10^{15} Btu) per year, the industrial sector is the second largest consumer of fossil fuels. This sector uses a mixture of natural gas (43 percent), fuel oil (8 percent), other petroleum fuels (34 percent), and coal (14 percent). The other petroleum fuels that are used include primarily liquified petroleum gas, asphalt and road oil, and other nonclassified fuels. Again, the distribution among the three fuel types varies substantially from State to State, with each of the three contributing significant fractions in most States. Notable exceptions are Hawaii, which relies almost exclusively on petroleum fuels; Alaska, which relies primarily on natural gas; and the northeastern States of Connecticut, New Hampshire, Rhode Island, and Vermont, which use almost no coal.

As shown in Table 6-1, substantially smaller quantities of fossil fuel are used in the commercial and residential sectors than are used in the utility and industrial sectors. The fuels used are primarily natural gas, fuel oil, and liquified petroleum gas (the "other petroleum fuels" in the residential category). Almost all States use a mixture of the fuels, but the distributions vary substantially, with some States like California and Louisiana using primarily natural gas and others like New Hampshire and Vermont using a much greater fraction of fuel oil. One unique case is Pennsylvania where anthracite coal is used in both the residential and commercial sectors.

In the individual sections below, additional information will be presented on the mercury content of the different fuels and on the relationship between fuel type and emissions. However, for any geographic area, the contribution of energy generation sources to mercury emissions will be a function of the

distribution of fuels used in the different sectors within the area.

The sources within the second combustion category are engaged primarily in waste disposal. Mercury emissions from these processes are related to the mercury levels in the waste. The different waste types are generally characterized with distinct source categories. Furthermore, these waste disposal practices are not strongly related. Consequently, each of these categories will be characterized individually within the sections below rather than in a general discussion here. The eight sections below have a consistent organization. First, the characteristics of the fuel or waste are described and, in the case of the waste combustion processes, the general source category is also described. Second, process descriptions are presented and emission points are identified. Third, available emission control measures are identified and described. Finally, emission factors are presented. A discussion of the sampling and analytical methods used to determine the mercury emission levels from combustion sources is presented in Section 9.

6.1 COAL COMBUSTION

As presented in Table 6-1, most coal combustion in the United States occurs in the utility and industrial sectors, with about 85 percent being bituminous and lignite combustion within the utility sector and about 14 percent being bituminous and lignite combustion in the industrial sector. Consequently, the focus of the discussion below will be on bituminous and lignite coal combustion in utility and industrial boilers. However, limited information on anthracite coal combustion will also be presented.

6.1.1 Coal Characteristics

The coal characteristics of greatest interest in evaluating mercury emissions from coal combustion are coal heating values and coal mercury content. Mercury emissions are a direct function of the mercury content, while heating values are used to convert emission factors between mass input-based and heat input-based activity levels. This section briefly summarizes the information about coal heating levels and mercury content contained in References 26 through 28. More complete summaries can be found in Reference 26, and detailed analyses of coal mercury content as a function of coal type and geographic region can be found in References 27 and 28.

Coal is a complex combination of organic matter and inorganic ash formed in geologic formations from successive layers of fallen vegetation and other organic matter. Coal types are broadly classified as anthracite, bituminous, subbituminous, or lignite, and classification is made by heating values and amounts of fixed carbon, volatile matter, ash, sulfur, and moisture.²⁹ Formulas for differentiating coals based on these properties are given in Reference 30. These four coal types are further subdivided into 13 component groups. Table 6-2 summarizes information about the heating values for these component groups.²⁶

The heating value of coal varies between coal regions, between mines within a region, between seams within a mine, and within a seam. The variability is minimal compared to that found with trace metal levels described below, but it may be important when fuel heat content is used as the activity level measure for source emission calculations. Data presented in Table 6-3 illustrate the regional variability of coal heat content. Heat content among coals from several different mines within a region appears to exhibit greater variability than either variability within a mine or within a seam. For the sample points presented

TABLE 6-2. COAL HEATING VALUES

Coal class	Component group	Definition	Source ^a	Heating value, kJ/kg (Btu/lb)	
				Range ^a	Mean ^a
Anthracite	A1	Meta-anthracite	PA,RI	21,580-29,530 (9,310-12,740)	25,560 (11,030)
	A2	Anthracite	CO,PA,NM	27,700-31,800 (11,950-13,720)	30,270 (13,000)
	A3	Semianthracite	AR,PA,VA	27,460-31,750 (11,850-13,700)	29,800 (12,860)
Bituminous	B1	Low volatile bituminous	AR,MD,OK,PA,WV	30,640-34,140 (13,220-14,730)	32,400 (13,980)
	B2	Medium volatile bituminous	AL,PA,VA	31,360-33,170 (13,530-14,310)	32,170 (13,880)
	B3	High volatile A bituminous	AL,CO,KS,KY,MO,NM,PA,TN,TX,UT,VA,WV	28,340-35,710 (12,230-14,510)	31,170 (13,450)
	B4	High volatile B bituminous	IL,KY,MO,OH,UT,WY	26,190-30,480 (11,300-13,150)	28,480 (12,290)
	B5	High volatile C bituminous	IL,IN,IA,MI	24,450-27,490 (10,550-11,860)	26,030 (11,230)
Subbituminous	S1	Subbituminous A	MT,WA	23,940-25,820 (10,330-11,140)	24,890 (10,740)
	S2	Subbituminous B	WY	21,650-22,270 (9,340-9,610)	21,970 (9,480)
	S3	Subbituminous C	CO,WY	19,280-19,890 (8,320-8,580)	19,580 (8,450)
Lignite	L1	Lignite A	ND,TX	16,130-17,030 (6,960-7,350)	16,660 (7,190)
	L2	Lignite B	NA	NA	NA

Source: Reference 26.

^aNA = not available.

TABLE 6-3. EXAMPLES OF COAL HEAT CONTENT VARIABILITY

Variability	Coal source	Coal heat content, Btu/lb		Percent variation about the mean
		Mean	Range ^a	
Intermine variability	Eastern U.S.	12,320	10,750 - 13,891	12.7
	Central U.S.	10,772	9,147 - 12,397	15
	Western U.S.	11,227	9,317 - 13,134	17
Intramine variability	Eastern U.S.	12,950	NA	4.8 ^b
		10,008	9,182 - 10,834	8.0
		12,000	11,335 - 12,665	5.5
	Central U.S.	12,480	NA	5.7 ^c
		10,975	9,667 - 12,284	12.0
	Western U.S.	10,351	9,791 - 10,911	5.4
Intraseam variability	Eastern U.S.	12,230	NA	3.0 ^d
	Central U.S.	10,709	10,304 - 11,113	3.7
	Western U.S.	11,540	NA	2.5 ^e

Source: Reference 26.

^aNA = not available.

^bBased on a standard deviation of 624.

^cBased on a standard deviation of 708.

^dBased on a standard deviation of 371.

^eBased on a standard deviation of 291.

in Table 6-3, intermine variability averaged 15 percent, intramine variability 7 percent, and intraseam variability 3 percent. Because few combustion sources burn coal from just one seam or one mine, coal heat content variability may significantly affect emission estimates that are being calculated using emission factors, coal use data, and coal heat content data, even if the source gets all its coal from the same area of the country.²⁶

To an even greater extent than the heating value, the mercury content of coal varies substantially among coal types, at different locations in the same mine, and across geographic regions. The most comprehensive source of information on coal composition is the United States Geological Survey (USGS) National Coal Resources Data System (NCRDS). Geochemical and trace element data are stored within the USCHEM file of NCRDS. As of October 1982, the file contained information on 7,533 coal samples representing all U.S. coal provinces. Trace element analysis for about 4,400 coal samples were included in the data base. This computerized data system was not accessed during the current study due to time and budgetary constraints and information from USGS that indicated that few data had been added to the system since 1972; however, a summary of the data presented in Reference 26 was reviewed. The most extensive source of published trace element data was produced by Swanson et al. of the USGS.²⁸ This report contains data for 799 coal samples taken from 150 producing mines and includes the most important U.S. coal seams. Data from the Swanson study was the initial input into the USCHEM file of NCRDS. The information presented here summarizes Brooks' review of the results published by White and Swanson.²⁶⁻²⁸ Note that those results are consistent with unpublished analyses conducted by USGS on the data contained in NCRDS as of 1989.³¹ More information on the sampling and analysis of mercury in coal is presented in Section 9.

Table 6-4 presents information on the mean concentration of mercury in coal and on the distributions of mercury concentrations by coal type. Bituminous and anthracite coals have the highest mean mercury concentrations, 0.21 parts per million by weight (ppmwt) and 0.23 ppmwt, respectively. The standard deviation of each mean either approaches or exceeds the mean, indicating strong variation in the data. Subbituminous coals have the greatest reported range of mercury concentrations (0.01 to 8.0 ppm).²⁶ Based on conversations with USGS personnel, the means reported in Table 6-4 are regarded as typical values for in-ground mercury concentration in coals in the United States.

TABLE 6-4. MERCURY CONCENTRATION IN COAL BY COAL TYPE

Coal type	No. of samples	Mercury concentration, ppmwt		
		Range	Arithmetic mean	Standard deviation
Bituminous	3,527	<0.01 to 3.3	0.21	0.42
Subbituminous	640	0.01 to 8.0	0.10	0.11
Anthracite	52	0.16 to 0.30	0.23	0.27
Lignite	183	0.30 to 1.0	0.15	0.14

Source: Reference 26.

The concentration of mercury in coal also varies by geographic region from which the coal is mined. Based on the "best typical" values for each region, which are footnoted in Table 6-5, coals from the Appalachian and Gulf Provinces have the highest mean mercury concentration, 0.24 ppmwt for both regions. Also, based on the best available data, the lowest mean concentration is found in coals from the Alaska region (0.08 ppmwt). However, note that another study showed substantially higher levels (4.4 ppmwt). That study also showed that the greatest range of concentration is found in coals from

TABLE 6-5. MERCURY CONCENTRATION IN COAL BY REGION

Region	No. of samples	Mercury concentration, ppmwt		
		Range	Arithmetic mean	Standard deviation
Appalachian	2,749	---	0.24 ^a	0.47
	331	<0.01-3.3	0.24 ^b	---
Interior	592	---	0.14 ^a	0.14
	155	0.01-0.83	0.14 ^b	---
	---	0.01-1.5	0.15	---
Illinois Basin ^c	82	0.03-1.6	0.21	0.22
	---	0.16-1.91	---	---
Gulf Province	38	---	0.24 ^a	0.19
	34	0.03-1.0	0.18 ^b	---
Northern Plains	371	---	0.11 ^a	0.10
	490	0.01-3.8	0.11	---
Rocky Mountains	184	---	0.09 ^a	0.12
	124	0.01-1.48	0.06 ^b	---
	---	0.01-8.0	0.11	---
Alaska	107	---	0.08 ^a	0.07
	18	0.02-63	4.4 ^b	---

Source: Reference 26.

^aValues from the White, et al. study are based on the most comprehensive data set currently available (the NCRDS) and may be used as typical values for mercury in coal from these regions.

^bValues from the Swanson, et al. study are included in the NCRDS. Arithmetic means from the entire NCRDS are more representative than means from this study, since the NCRDS contains many more coal samples. The Swanson, et al. data are included to give an idea of the range of values for mercury content in individual coal samples from each region.

^cEastern section of Interior Province.

the Alaska region with a reported range of 0.02 to 63 ppmwt.²⁶ The means reported in Table 6-5 may be regarded as typical in-ground concentrations of mercury in coals from each geographic region.

6.1.2 Process Description^{26,29,32}

As shown in Table 6-1, almost all coal combustion occurs in utility and industrial boilers. Almost all of the coal burned is bituminous and subbituminous (95 percent) and lignite (4 percent).²⁶ However, the processes used for the different coals are comparable. The paragraphs below first describe the boilers used for bituminous coal combustion. Then, lignite and anthracite combustion are described briefly. References 29 and 32 offer additional details on these processes.

The two major coal combustion techniques used to fire bituminous and subbituminous coals are suspension firing and grate firing. 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.

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 and suspension-fired through the burners to the combustion chamber. 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 dry ash removal techniques are used. In wet bottom (slag tap) furnaces, coals with low ash fusion temperatures are used, and molten ash is drained from the bottom of the furnace.

Cyclone furnaces burn low ash fusion temperature coal crushed to a 4-mesh size. The coal is fed tangentially, with primary air, to a horizontal cylindrical combustion chamber. Small coal particles are burned in suspension, while the 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 that is drained from the bottom of the furnace 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 grate. Combustion occurs partially in suspension and partially on the grate. Because the entrained particles in the furnace exhaust have substantial carbon, fly ash reinjection from mechanical collectors is commonly used to improve boiler efficiency. Ash residue in 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. "Overfeed" applies because the coal is fed onto the moving grate under an adjustable gate. Conversely, in "underfeed" stokers, coal is fed upward into the firing zone by mechanical rams or screw conveyers. The coal moves in a channel, known as a retort, from which it is forced upward, spilling over the top of each side to feed the fuel bed. Combustion is completed by the time the bed reaches the side dump grates from which the ash is discharged to shallow pits.

The next most common coal used in the U.S. is lignite. Lignite is a relatively young coal with properties intermediate to those of bituminous coal and peat. Because lignite has a high moisture content (35 to 40 weight percent) and a low wet basis heating value (16,660 kJ/kg [7,190 Btu/lb]), it generally is used

as a fuel only in areas in which it is mined. Lignite is used mainly for steam/electric production in power plants and typically is fired in larger pulverized coal-fired or cyclone-fired boilers.

Anthracite coal is a high-rank coal with more fixed carbon and less volatile matter than either bituminous coal or lignite. Because of its low volatile matter content and slight clinkering, anthracite is most commonly fired in medium-sized traveling grate stokers and small hand-fired units. Some anthracite (occasionally with petroleum coke) is used in pulverized coal-fired boilers, and it may be blended with bituminous coal. Because of its low sulfur content (typically less than 0.8 weight percent) and minimal smoking tendencies, anthracite is considered a desirable fuel in areas where it is readily available. In the United States, anthracite is mined primarily in northeastern Pennsylvania and consumed mostly in Pennsylvania and surrounding States. The largest use of anthracite is for space heating. Lesser amounts are employed for steam/electric production, typically in underfeed stokers and pulverized coal dry-bottom boilers.

Although small quantities of mercury may be emitted as fugitive particulate matter from coal storage and handling operations, the primary source of mercury and mercury compound emissions from coal combustion is the combustion stack. Because the combustion zone in boilers operates at temperatures in excess of 1100°C (2000°F), the mercury in the coal is vaporized and exits the combustion zone as a gas. As the combustion gases pass through the boiler and the air pollution control system, they cool, and some of the mercury and mercury compounds may condense on the surface of fine particles. The relative fractions of vapor- and particle-phase mercury in the exhaust stack depend primarily on the temperature of the air pollution control system, and the amount of residual carbon in the coal fly ash (some of the vaporous mercury and mercury compounds will

adsorb onto carbon at temperatures present in some air pollution control devices). To date, little information has been obtained on these distributions.

6.1.3 Emission Control Measures²⁹

Data on the performance of coal combustion emission control measures, relative to mercury and mercury compounds, are quite sparse. Furthermore, many of the data that are available are somewhat dated and are of questionable reliability.

Emission control measures for coal-fired boilers include controls based on combustor design and operating practices that are directed primarily at nitrogen oxides (NO_x) and particulate matter (PM) control and add-on air pollution control devices that are designed for acid gas and PM control. Those measures that are most likely to affect mercury control are add-on control systems designed for both PM and acid gas control. The primary types of PM control devices used for coal combustion include multiple cyclones, electrostatic precipitators, fabric filters (baghouses), and wet scrubbers, while both wet and dry flue gas desulfurization (FGD) systems are used for sulfur dioxide (SO_2). Some measure of PM control is also obtained from ash settling in boiler/air heater/economizer dust hoppers, large breeches and chimney bases, but these mechanisms will not reduce mercury emissions.

Electrostatic precipitators (ESP) are the most common high efficiency control devices used on pulverized coal and cyclone units. These devices are also being used increasingly on stokers. Generally, PM collection efficiencies are a function of the specific collection area (i.e., the ratio of the collection plate area per volumetric flow rate of flue gas through the device). Particulate matter efficiencies of 99.9 weight percent have been measured with ESP's. Fabric filters have recently seen increased use in both utility and industrial applications both as

a PM control measure and as the collection mechanism in dry FGD systems, generally achieving about 99.8 percent PM control. Wet scrubbers are also used to control PM emissions, although their primary use is to control emissions of sulfur oxides. Because, unlike the other PM control devices, wet scrubbers reduce the gas stream temperature, they may be more effective than the other controls in removing condensible PM, such as mercury. The other PM control devices would require some type of acid gas control, such as a spray dryer.

Mechanical collectors, generally multiple cyclones, are the primary means of control on many stokers and are sometimes installed upstream of high efficiency control devices in order to reduce the ash collection burden. Depending on application and design, multiple cyclone PM efficiencies can vary tremendously. However, these systems are relatively inefficient for fine particles and are not likely to provide measurable control of mercury emissions, which are primarily in the vapor and fine particle fractions of the exhaust.

The section on emission factors below presents the available data on emission control system performance. However, in evaluating the potential emissions from a facility or group of facilities, any assumptions about control system performance, including those based on the data presented herein, should be examined carefully to assure that they are supported by reliable test data obtained via methods comparable to those described in Section 9. Also, performance estimates must be consistent with the physical and chemical properties of the compounds being emitted and with the operating characteristics of the systems being evaluated.

6.1.4 Emissions

The primary source of mercury emissions from coal combustion operations is the combustion gas exhaust stack. Small amounts of

mercury also may be emitted as a component of the fugitive PM emissions from coal and ash handling.

Two distinct sources of information were used to develop and evaluate mercury emission factors for coal combustion. A third source was considered but was not used. First, the data presented above on mercury concentrations in coal and coal heating values were used to develop mass balance-based emission factors under the conservative assumption that all mercury charged with the coal is emitted in the stack gas. The assumption is based on a lack of data on the effectiveness of mercury controls for coal combustion. Second, the emission factors presented in the coal and oil Locating and Estimating (L&E) document were reviewed and summarized.²⁶ No attempt was made to verify the sources of data used in the coal and oil L&E document or to rate the emission factors that were developed therein. The results obtained from these two methods are discussed separately in the paragraphs below. Then the relative merits of the emission factors obtained by the different methods are examined and the best typical emission factors are identified. The third approach, using controlled emission factors from a summary of the PISCES literature data base, was considered, but those results are based on a much smaller number of data points. Data were excluded as unreliable for a variety of reasons, including uncharacteristically low ESP control efficiencies, but the variability in the data did not improve significantly.³³

The information presented in the literature indicates that virtually 100 percent of the mercury contained in the coal is emitted from the furnace as either a vapor or fine PM. Consequently, the coal heating values presented in Table 6-2 and the coal mercury concentrations presented in Table 6-4 can be used to develop emission factors for major coal types under the conservative assumption that all mercury in the coal is emitted. Furthermore, note that the coal composition data in Table 6-4 are

based on in-ground mercury concentrations and that calculated emission factors shown in Table 6-6 are based on the conservative assumption that as-fired coal contains equivalent concentrations. If mercury concentrations are reduced during coal cleaning operations, these estimates will be biased high. The Utility Air Regulatory Group (UARG) and the Electric Power Research Institute (EPRI) are working with the USGS to compile data on the extent of coal washing in the United States and its effects on the trace metal content of coal. This study is expected to be completed by the end of 1993. Preliminary data from the U.S. Department of Energy indicates that there is reduction in mercury concentrations from coal cleaning (10 to 25 percent for commercial cleaning and 25 to 50 percent for laboratory cleaning).³⁴ The mercury emission factors derived from these reduced mercury concentrations are also shown in Table 6-6.

TABLE 6-6. CALCULATED UNCONTROLLED MERCURY EMISSION FACTORS FOR COAL COMBUSTION

Coal type	Calculated mercury emission factors ^a			
	kg/10 ¹⁵ J	lb/10 ¹² Btu	g/Mg coal	10 ⁻³ lb/ton coal
Bituminous ^b	7.0 (5.2-6.3)	16 (12-14)	0.21 (0.16-0.19)	0.42 (0.32-0.38)
Subbituminous ^c	4.5 (2.9-4.0)	10 (7.5-9.0)	0.10 (0.075-0.090)	0.20 (0.15-0.18)
Anthracite ^d	7.6 (5.7-6.8)	18 (14-17)	0.23 (0.17-0.21)	0.46 (0.34-0.41)
Lignite ^e	9.0 (6.8-8.1)	21 (16-19)	0.15 (0.11-0.14)	0.30 (0.22-0.27)

^aValues in parenthesis are based on a 10 to 25 percent reduction in mercury concentrations from commercial coal cleaning.

^bBased on arithmetic average of the five average heating values in Table 6-2.

^cBased on arithmetic average of the three average heating values in Table 6-2.

^dBased on average heating value for coal category A2 in Table 6-2.

^eBased on average heating value for coal category L1 in Table 6-2.

A comprehensive summary of the test data generated prior to 1989 for coal-fired boilers and furnaces is presented in Reference 26. The data from individual tests that are presented

in that report are compiled in Table B-1 in Appendix B. Table 6-7 summarizes these data as a function of coal type and control status. Note the wide range of emission factors for each coal type. In addition to the variability in coal heat content and the uncertainty in mercury sampling and analysis, this range reflects the substantial variation in coal mercury content and highlights the need to obtain coal-specific mercury data to calculate emission estimates whenever possible. Also note that the data are combined across industry sector and boiler type because these parameters are not expected to have a substantial effect on emission factors.

As noted in Reference 26, the available test data, although limited, indicate that essentially no control of mercury in flue gas is achieved by multiclones, up to 50 percent control is achieved by ESP's, and limited scrubber data show mercury efficiencies of 50 and 90 percent. Long-term scrubber performance will depend on the blowdown rate for the scrubber, with efficiency falling if the system approaches equilibrium. However, according to literature references discussed in Reference 26, these control efficiencies may be biased high because they are based on data collected using older test methods, which tended to collect mercury vapor inefficiently. Consequently, these estimates represent upper bounds of efficiencies. More information on the sampling and analysis of mercury in flue gas is presented in Section 9.

Based on review of the available data, the best estimates for uncontrolled emission factors for typical coal combustion facilities are those obtained from a mass balance using coal composition data. This approach was selected because the available test data are of uncertain quality, and the coal concentration data are representative of a much larger industry segment. Controlled emission factors were obtained by applying an assumed 0 percent efficiency for mechanical collectors, 0 to 50 percent control for ESP's, and 50 to 90 percent control for

TABLE 6-7. MEASURED MERCURY EMISSION FACTORS FOR COAL COMBUSTION

Coal type ^a	Control status ^b	No. of boilers	No. of data points	Measured mercury emission factors							
				kg/10 ¹⁵ J		lb/10 ¹² Btu		g/Mg coal ^d		10 ⁻³ lb/ton coal ^e	
				Mean	Range ^c	Mean	Range ^c	Mean	Range ^c	Mean	Range ^c
B ^d	UN	17	34	3.8	0.005-133	8.8	0.011-308	0.11	0.00015-4.0	0.23	0.00029-8.0
B ^d	MP or MC	9	15	12.9	0.60-77	29.9	1.4-180	0.39	0.018-2.3	0.78	0.036-4.7
B ^d	ESP or MP/ESP	29	59	3.4	0.18-9.6	8.0	0.41-22.3	0.10	0.0055-0.29	0.21	0.011-0.58
B ^d	ESP-2 stage	1	5	0.086	0.005-0.25	0.20	0.011-0.56	0.0026	0.00015-0.0075	0.0052	0.00029-0.015
B ^d	WS or MC/WS	5	5	7.9	b.d.-37	18.4	b.d.-86	0.24	b.d.-1.1	0.48	b.d.-2.2
B ^d	FF	1	1	2.0	--	4.6	--	0.060	--	0.12	--
SB ^e	UN	3	5	13.0	0.28-35	30.2	0.64-81	0.29	0.0062-0.78	0.58	0.012-1.5
SB ^e	ESP or MP/ESP	3	5	1.2	0.16-1.8	2.7	0.37-4.1	0.027	0.0035-0.040	0.052	0.0071-0.078
SB ^e	WS	2	2	3.4	2.1-4.7	8.0	4.9-11	0.075	0.047-0.10	0.15	0.094-0.21
L ^f	MC	4	4	4.1	1.9-9.5	9.6	4.4-22	0.068	0.032-0.16	0.14	0.063-0.32
L ^f	ESP	3	3	0.18	0.099-0.23	0.41	0.23-0.53	0.0030	0.0016-0.0038	0.0059	0.0033-0.0076
A ^g	UN	3	3	2.3	1.5-3.0	5.3	3.5-7.0	0.070	0.045-0.091	0.14	0.091-0.18

Source: Reference 26.

^aB = bituminous, SB = subbituminous, L = lignite, A = anthracite.

^bUN = uncontrolled, MP = mechanical precipitation system, MC = multiclone, ESP = electrostatic precipitator, WS = wet scrubber.

^cb.d. = below detection limits.

^dBased on arithmetic average of the five average heating values in Table 6-2.

^eBased on arithmetic average of the three average heating values in Table 6-2.

^fBased on average heating value for coal category L1 in Table 6-2.

^gBased on average heating value for coal category A2 in Table 6-2.

wet scrubbers. Data were inadequate to estimate efficiencies for systems equipped with fabric filters. The resultant best typical emission factors are shown in Table 6-8.

The ESP-controlled emission factors for bituminous, subbituminous, and lignite coal were compared with the median and mean ESP-controlled emission factors summarized from the PISCES data base.³³ For bituminous and subbituminous coals, the emission factors for mercury presented in this L&E were in the same range as those from PISCES. The mercury emission factor presented here for lignite coals was higher than that from PISCES by almost two orders of magnitude. However, the PISCES results are based on a much smaller number of samples due to the exclusion of data considered unreliable. The variability in the PISCES data was not improved significantly with the exclusion.

The mercury emission factors presented for coal combustion should be viewed as the most realistic nationwide estimates possible, based on what little data are available. It should be recognized that, as with the PISCES data, there is considerable uncertainty in these estimates. The uncertainty in the L&E estimates is due to the wide variability in mercury concentrations in coal, the variability in coal heat content, and the uncertainty in sampling and analytical methodologies for detecting mercury. Therefore, these estimates should not be used to determine emissions from specific coal combustion facilities.

6.2 FUEL OIL COMBUSTION

As shown in Table 6-1, based on energy consumption estimates by the U.S. Department of Energy, fuel oil use spans the four sectors of energy users. Distillate fuel oil is used extensively in all sectors with the largest use in the utility (31 percent) and the industrial (32 percent) sectors, but with substantial amounts used in both the commercial (13 percent) and residential (23 percent) sectors. Residual oil is used primarily in the

TABLE 6-8. BEST TYPICAL MERCURY EMISSION FACTORS FOR COAL COMBUSTION

Coal type ^a	Control status ^b	Typical mercury emission factors			
		kg/10 ¹⁵ J	lb/10 ¹² Btu	g/Mg coal	10 ⁻³ lb/ton coal
B	Uncontrolled	7.0	16	0.21	0.42
B	Mechanical collector	7.0	16	0.21	0.42
B	ESP	3.5-7.0	8-16	0.10-0.21	0.21-0.42
B	Wet scrubber	0.7-3.5	1.6-8	0.021-0.10	0.042-0.21
SB	Uncontrolled	4.5	10	0.10	0.20
SB	Mechanical collector	4.5	10	0.10	0.20
SB	ESP	2.2-4.5	5-10	0.050-0.10	0.10-0.020
SB	Wet scrubber	0.4-2.2	1-5	0.010-0.050	0.02-0.10
A	Uncontrolled	7.6	18	0.23	0.46
A	Mechanical collector	7.6	18	0.23	0.46
A	ESP	3.8-7.6	9-18	0.12-0.23	0.23-0.46
A	Wet scrubber	0.7-3.8	1.8-9	0.023-0.12	0.046-0.23
L	Uncontrolled	9.0	21	0.15	0.30
L	Mechanical collector	9.0	21	0.15	0.30
L	ESP	4.5-9.0	10-21	0.075-0.15	0.15-0.30
L	Wet scrubber	0.9-4.5	2.1-10	0.015-0.075	0.030-0.15

^aB = bituminous, SB = subbituminous, A = anthracite, L = lignite.

^bESP = electrostatic precipitator.

industrial (56 percent) and commercial (33 percent) sectors. Because the oil combustion process is not complex, and control systems are not widely applied to oil-fired units, the discussion below will focus on fuel characteristics and on emissions from oil-fired units.²⁵

6.2.1 Fuel Oil Characteristics²⁶

The fuel oil characteristics of greatest importance for characterizing mercury emissions from fuel oil combustion are the heating value and the mercury content of the oil. The heating value is used for converting from emission factors with mass- or volume-based activity levels to those with activity levels based on heat input.

The term fuel oil covers a variety of petroleum products, including crude petroleum, lighter petroleum fractions such as kerosene, and heavier residual fractions left after distillation. To provide standardization and means for comparison, specifications have been established that separate fuel oils into various grades. Fuel oils are graded according to specific gravity and viscosity, with No. 1 Grade being the lightest and No. 6 the heaviest. The heating value of fuel oils is expressed in terms of kJ/L (Btu/gal) of oil at 16°C (60°F) or kJ/kg (Btu/lb) of oil. The heating value per gallon increases with specific gravity because there is more weight per gallon. The heating value per mass of oil varies inversely with specific gravity because lighter oil contains more hydrogen. For an uncracked distillate or residual oil, heating value can be approximated by the following equation:

$$\text{Btu/lb} = 17,660 + (69 \times \text{API gravity})$$

For a cracked distillate, the relationship becomes:

$$\text{Btu/lb} = 17,780 + (54 \times \text{API gravity})$$

Table 6-9 provides an overall summary of the heating values of typical fuel oils used in the U.S., and Table 6-10 shows the variability in fuel oil heating values used in various regions of the country. Appendix B of Reference 26 provides additional details.

The data base for mercury content in fuel oils is much more limited than the coal mercury content data base. A number of petroleum industry associations were contacted, but none who responded have done any research on metals content in fuel oils. No single centralized data base is available, and the information presented below is based on limited data from individual studies.

Concentrations of mercury in fuel oil depend upon the type of oil used. No comprehensive oil characterization studies have been done, but data in the literature report mercury concentrations in crude oil ranging from 0.023 to 30 ppmwt, while the range of concentrations in residual oil is 0.007 to 0.17 ppmwt. Because only a single mean value was found in the literature for mercury concentration in distillate oil, no conclusions can be drawn about the range of mercury in distillate oil. Table 6-11 lists typical values for mercury in oils, which were obtained by taking the average of the mean values found in the literature. The value for distillate oil is the single data point found in the literature and may not be as representative as the values for residual and crude oils.

6.2.2 Process Description^{29,32}

Fuel oils are broadly classified into two major types: distillate and residual. Distillate oils (fuel oil grade Nos. 1 and 2) are more volatile and less viscous than residual

TABLE 6-9. TYPICAL HEATING VALUES OF FUEL OILS

	FUEL OIL GRADES					
	No. 1	No. 2	No. 4	No. 5	No. 6	
Type	Distillate	Distillate	Very light residual	Light residual	Residual	Crude ^b
Color	Light	Amber	Black	Black	Black	
Heating value ^a						
kJ/L	38,200	40,900	40,700	41,200	41,800	40,000-42,300
(Btu/gal)	(137,000)	(141,000)	(146,000)	(148,000)	(150,000)	(144,000-152,000)
kJ/kg	45,590-46,030	44,430-45,770	42,370-44,960	41,950-44,080	40,350-43,800	40,700-43,300
(Btu/lb)	(19,670-19,860)	(19,170-19,750)	(18,280-19,400)	(18,100-19,020)	(17,410-18,900)	(17,500-18,600)

Source: References 26 and 35.

^aThe distillate samples, as well as the residual samples, analyzed for Btu/gal and Btu/lb heating values are different; therefore, the heating values presented do not directly correspond to one another.

^bThese crude oil values are based on a limited number of samples from West Coast field sites presented in Reference 34 and may not be representative of the distribution of crude oils processed in the United States.

TABLE 6-10. TYPICAL FUEL OIL HEATING VALUES FOR SPECIFIC REGIONS

Region	No. 1 fuel oil			No. 2 fuel oil			No. 4 fuel oil		
	Heating value, kJ/L (Btu/gal)			Heating value, kJ/L (Btu/gal)			Heating value, kJ/L (Btu/gal)		
	No. of samples	Range	Average	No. of samples	Range	Average	No. of samples	Range	Average
Eastern	33	36,900-37,800 (132,600-136,700)	37,400 (134,200)	58	37,100-40,800 (133,100-148,800)	38,800 (139,600)	1	---	40,700 (148,000)
Southern	13	37,000-37,700 (132,800-136,400)	37,400 (134,300)	18	38,000-39,400 (138,400-141,600)	38,800 (139,400)	0	---	---
Central	27	36,900-37,800 (132,600-136,700)	37,300 (134,000)	36	37,800-40,800 (136,900-148,800)	38,800 (139,200)	2	40,700-41,800 (148,000-150,100)	41,200 (149,000)
Rocky Mountain	14	37,100-37,800 (133,100-136,100)	37,400 (134,200)	17	37,900-39,100 (138,100-140,400)	38,700 (139,000)	2	41,800-41,900 (150,100-150,600)	41,800 (150,300)
Western	18	36,700-37,800 (131,700-136,200)	37,600 (134,800)	18	37,900-39,100 (138,100-140,600)	38,700 (139,000)	0	---	37,600 (134,800)

Region	No. 5 fuel oil (light)			No. 6 fuel oil		
	Heating value, kJ/L (Btu/gal)			Heating value, kJ/L (Btu/gal)		
	No. of samples	Range	Average	No. of samples	Range	Average
Eastern	1	---	41,300 (148,400)	17	40,800-43,800 (147,000-157,800)	43,300 (151,800)
Southern	0	---	---	14	41,800-43,800 (150,600-158,600)	42,800 (152,800)
Central	4	41,300-42,200 (148,400-151,500)	41,700 (149,800)	10	41,800-44,200 (150,800-158,800)	42,800 (152,800)
Rocky Mountain	2	42,800-43,800 (153,800-158,600)	43,200 (155,200)	7	42,300-44,300 (151,900-159,200)	43,100 (154,800)
Western	0	---	---	12	41,700-45,600 (148,900-163,500)	43,000 (154,400)

Source: Reference 28.

TABLE 6-11. MERCURY CONCENTRATION IN OIL BY OIL TYPE

Fuel oil type	No. of samples	Mercury concentration, ppmwt	
		Range	Typical value
Residual No. 6	14	0.007-10	0.056 ^a
Distillate No. 2	1	--	0.40 ^b
Crude	46	0.007-30	3.5 ^c

Source: Reference 26.

^aAverage of 14 data points with 10 ppm concentration discarded as an outlier.

^bBased on single data point. May not be representative.

^cAverage of 46 data points was 6.86; if the single point value of 23.1 is eliminated, average based on 45 remaining data points is 1.75. However, the largest study with 43 data points had an average of 3.2 ppmwt. A compromise value of 3.5 ppmwt was selected as the best typical value.

oils, having negligible ash and nitrogen contents and usually containing less than 0.1 weight percent sulfur. No. 4 residual oil is sometimes classified as a distillate; No. 6 is sometimes referred to as Bunker C. Being more viscous and less volatile than distillate oils, the heavier residual oils (Nos. 5 and 6) must be heated to facilitate handling and proper atomization. Because residual oils are produced from the residue after lighter fractions (gasoline and distillate oils) have been removed from the crude oil, they contain significant quantities of ash, nitrogen, and sulfur. Small amounts of crude oil are sometimes burned for steam generation for enhanced oil recovery or for refinery operations.

Oil-fired boilers and furnaces are simpler and have much less variation in design than the coal-fired systems described earlier. The primary components of the system are the burner, which atomizes the fuel and introduces it along with the combustion air into the flame, and the furnace, which provides the residence time and mixing needed to complete combustion of the fuel. The primary difference in systems that fire distillate

oil and residual oil is that the residual oil systems must have an oil preheater to reduce the viscosity of the oil so that it can be atomized properly in the burner. Systems that fire distillate oil and residual oil also have different atomization methods.

The only source of mercury emissions from oil-fired boilers and furnaces is the combustion stack. Because the entire fuel supply is exposed to high flame temperatures, essentially all of the mercury and mercury compounds contained in the fuel oil will be volatilized and exit the furnace with the combustion gases. Unless these combustion gases are exposed to low-temperature air pollution control systems and high-efficiency PM control systems, which typically are not found on oil-fired units, the mercury and mercury compounds will be exhausted in vapor phase through the combustion stack.

6.2.3 Emission Control Measures^{26,32}

The three types of control measures applied to oil-fired boilers and furnaces are boiler modifications, fuel substitution, and flue gas cleaning systems. Only fuel substitution and flue gas cleaning systems will affect mercury emissions. Fuel substitution is used primarily to reduce SO₂ and NO_x emissions. However, if the substituted fuels have lower mercury concentrations, the substitution will also reduce mercury emissions. Because PM emissions from oil-fired units are generally much lower than those from coal-fired units, high-efficiency PM control systems are generally not employed on oil-fired systems. Consequently, these flue gas cleaning systems are not likely to achieve substantial mercury control. However, the flue gas cleaning systems that are used on oil-fired units are described briefly below.

Flue gas cleaning equipment generally is employed only on larger oil-fired boilers. Mechanical collectors, a prevalent

type of control device, are primarily useful in controlling PM generated during soot blowing, during upset conditions, or when a very dirty heavy oil is fired. During these situations, high efficiency cyclonic collectors can achieve up to 85 percent control of PM, but negligible control of mercury is expected with mechanical collectors.

Electrostatic precipitators are commonly used in oil-fired power plants. Older ESP's may remove 40 to 60 percent of the PM, but negligible mercury control is expected. Newer ESP's may be more efficient, but no data are available for oil-fired power plants. Scrubbing systems have been installed on oil-fired boilers to control both sulfur oxides and PM. Similar to systems applied to coal combustion (presented in Reference 26), these systems can achieve PM control efficiencies of 50 to 90 percent. Because they provide gas cooling, some mercury control may be obtained, but no data are available on their performance.

6.2.4 Emissions

The only substantive source of mercury emissions from fuel oil combustion operations is the combustion gas exhaust stack. Three types of information were used to develop emission factors for oil combustion. First, the data described above on fuel oil heating value and mercury content of fuel oils were used to develop emission factors by mass balance, assuming conservatively that all mercury fired with the fuel oil is emitted through the stack. Second, the emission factors from the coal and oil L&E document were evaluated and summarized, but no attempt was made to verify original references or to rate these data. Finally, rated emission test data developed in preparation of this document were evaluated and summarized. The paragraphs below first present the results generated from each of the three sources. Then, the relative merits of the emission factors generated via each of the procedures are discussed, and the best "typical" emission factors are identified.

The literature on fuel oil combustion suggests that essentially all mercury in the fuel oil is vaporized in the combustion zone and exhausted as a vapor in the combustion gas stream. Using the assumption that 100 percent of the mercury in fuel oil leaves the boiler or furnace in the exhaust gases, the data in Tables 6-9 and 6-11 were used to calculate uncontrolled emission factors for No. 2 distillate and No. 6 residual oil. Data presented in Reference 34, which show average crude oil heating values of 42,500 kJ/kg (18,300 Btu/lb) and 41,300 kJ/L (148,000 Btu/gal), can be combined with the mercury content data in Table 6-11 to calculate uncontrolled emission factors for crude oil combustion. The results of these calculations are presented in Table 6-12.

TABLE 6-12. CALCULATED UNCONTROLLED MERCURY EMISSION FACTORS FOR FUEL OIL COMBUSTION

Fuel oil type	Calculated mercury emission factors					
	kg/10 ¹⁵ J	lb/10 ¹² Btu	g/Mg fuel oil	10 ⁻³ lb/ton fuel oil	g/10 ³ L fuel oil	lb/10 ⁶ gal fuel oil
Residual No. 6 ^a	1.4	3.3	0.056	0.11	0.058	0.50
Distillate No. 2 ^a	8.8	21	0.40	0.80	0.36	3.0
Crude ^b	84	190	3.5	7.0	3.5	28

^aBased on typical heating values in Table 6-9 and mercury concentrations in Table 6-11.

^bBased on average crude oil heating values in Reference 35 and mercury concentrations in Table 6-11.

A comprehensive summary of the emission data generated prior to 1989 was prepared by Brooks.²⁶ These somewhat dated results are tabulated in Table 6-13. Note that both the residual and distillate values presented in Table 6-13 are consistently less than the calculated values presented in Table 6-12. Brooks noted that for those tests for which data were sufficient to calculate mercury input rates, the measured emissions ranged from 3 to 20 percent of the mercury in the fuel.²⁶ Mercury is quite volatile and is expected to be emitted from the combustion process as a vapor. These results suggest that the emission test

TABLE 6-13. MEASURED MERCURY EMISSION FACTORS FOR FUEL OIL COMBUSTION

Fuel type	Industry sector ^a	Control status ^b	Fuel Hg content, ppmwt	Measured mercury emission factors						Date
				kg/10 ¹⁵ J	lb/10 ¹² Btu	g/Mg fuel oil ^c	10 ⁻³ lb/ton fuel oil ^c	g/10 ³ L fuel oil ^c	lb/10 ⁶ gal fuel oil ^c	
Residual No. 6	I	MC/WS	---	0.099	0.23 ^d	0.0042	0.0084	0.0041	0.034	1979
Residual No. 6	I	MC	---	0.60	1.4 ^d	0.025	0.051	0.025	0.21	1979
Residual No. 6	I	UN	<0.01	0.47	1.1	0.020	0.040	0.020	0.16	1978
Residual No. 6	I	UN	<0.01	0.47	1.1	0.020	0.040	0.020	0.16	1978
Residual No. 6	I	UN	<0.01	0.016	0.037	0.00067	0.0013	0.00067	0.0056	1978
1:1 Residual No. 6/Crude	U	UN	0.04	0.056	0.13	0.0024	0.0047	0.0024	0.019	1981
1:1 Residual No. 6/Crude	U	UN	0.03	0.031	0.072	0.0013	0.0026	0.0013	0.011	1981
1:1 Residual No. 6/Crude	U	UN	0.04	0.022	0.052	0.00093	0.0019	0.00093	0.0077	1981
Distillate No. 2 ^e	R	UN	---	1.2	2.8 ^f	0.054	0.11	0.049	0.39	1979
Distillate No. 2 ^e	R	UN	0.4	6.0	14	0.27	0.54	0.25	2.0	1981
Distillate No. 2 ^e	R	UN	0.4	7.3	17	0.33	0.66	0.30	2.4	1981

Source: Reference 26.

^aI = industrial, U = utility, R = residential.

^bMC = multiclone, WS = wet scrubber, UN = uncontrolled.

^cBased on typical residual and distillate fuel oil heating values in Table B-9 and average crude oil heating values in Reference 10.

^dValues obtained at outlet from and inlet to a wet scrubber at a single facility.

^eType of distillate oil not specified.

^fAverage of eight tests on seven units.

results are biased low, probably because they were collected using older test methods, in which the impinger solutions in the sampling train captured mercury vapors inefficiently. Consequently, the test data in Table 6-13 should be used cautiously. More information on the sampling and analysis of mercury in fuel oil is presented in Section 9.

As a part of this study, three test reports prepared as a part of the California "Hot Spots" program were reviewed.³⁵⁻³⁷ The emission factors generated from these three reports are summarized in Table 6-14. Each of the reports contained the data on fuel oil characteristics needed to calculate mercury input rates, so Table 6-14 contains both calculated emission factors based on mercury input levels and measured emission factors based on stack tests. Because mercury levels in all of the fuel oils tested were below detection limits, all calculated emission factors are reported as "less than" values. Note that only one of the three tests showed mercury levels above the detection limit in the stack. That test showed measured emissions to be substantially greater than mercury input to the process, making the results suspect. These discrepancies may be a function of the analytical problems that have been reported for mercury methods applied to combustion sources. These problems are discussed in more detail in Section 9. On balance, these data provide little information for emission factor development.

Given the limited emission test data available and the concerns about possible biases in those data, the mass balance approach was used to estimate the best "typical" emission factor for distillate and residual fuel oil combustion. Because only a single data point was available for distillate oil, the data in Table 6-11 were used to develop a weighted average mercury concentration in distillate and residual oils of 0.13 ppmwt. This concentration was combined with the average heating values shown in Table 6-9 to obtain the best estimate of typical emission factors for distillate and residual oil combustion.

TABLE 6-14. MERCURY EMISSION FACTORS FOR FUEL OIL COMBUSTION
GENERATED FROM CALIFORNIA "HOT SPOTS" TESTS

Process type	Fuel oil type	Calculated mercury emission factors ^a						Measured mercury emission factors ^a					
		kg/10 ¹⁵ J	lb/10 ¹² Btu	g/Mg fuel oil	10 ⁻³ lb/ton fuel oil	g/10 ³ L fuel oil	lb/10 ⁶ gal fuel oil	kg/10 ¹⁵ J	lb/10 ¹² Btu	g/Mg fuel oil	10 ⁻³ lb/ton fuel oil	g/10 ³ L fuel oil	lb/10 ⁶ gal fuel oil
Pipeline/ process heater ^b	Crude	<2.4	<5.6	<0.10	<0.20	<0.097	<0.81	<0.052	<0.12	<0.0022	<0.0044	<0.0021	<0.018
Generator ^c	Crude	<2.4	<5.6	<0.10	<0.21	<0.10	<0.83	14.7	34.1	0.62	1.2	0.61	5.1
Power boiler ^d	Residual	<2.3	<5.5	<0.10	<0.21	<0.10	<0.83	<15.0	<34.8	<0.65	<1.3	<0.63	<5.3

Source: References 35-37.

^aFor crude oil, emission factors were based on assumed crude oil heating value of 42,500 kJ/kg (18,300 Btu/lb) and density of 0.97 kg/L (8.1 lb/gal). For residual oil, emission factors were based on residual oil heating value of 43,800 kJ/kg (18,800 Btu/lb) and density of 0.98 kg/L (8.2 lb/gal).

^bMercury detection limit is 0.1 mg/kg.

^cMercury detection limit is 0.1 mg/L.

^dMercury detection limit is 0.1 mg/L.

The available information on uncontrolled mercury emissions from crude oil combustion is ambiguous. The limited test data presented in Tables 6-13 and 6-14 show measured factors that range from 0.02 to 15 kg/10¹⁵ J (0.05 to 34 lb/10¹² Btu), a range of almost three orders of magnitude. The calculated emission factor of 84 kg/10¹⁵ J (190 lb/10¹² Btu), which is based on limited fuel composition and heating value data, expands the range even further. Because these data are quite sparse and the relative quality of the data is uncertain, the midpoint of the range was selected as the best "typical" emission factor.

The uncontrolled emission factors for distillate, residual, and crude oil are presented in Table 6-15. Data are insufficient to develop controlled emission factors for fuel oil combustion. There is considerable uncertainty in these emission factor estimates due to the variability of mercury concentrations in fuel oil, the incomplete data base on distillate oil, and the uncertainty in sampling and analysis for detecting mercury. Therefore, these estimates should not be used to determine emissions from specific oil-fired units.

TABLE 6-15. BEST TYPICAL MERCURY EMISSION FACTORS FOR FUEL OIL COMBUSTION

Fuel oil type	Typical mercury emission factors					
	kg/10 ¹⁵ J	lb/10 ¹² Btu	g/Mg fuel oil	10 ⁻³ lb/ton fuel oil	g/10 ³ L fuel oil	lb/10 ⁶ gal fuel oil
Residual No. 6	3.0	7.2	0.13	0.26	0.12	1.1
Distillate No. 2	2.9	6.8	0.13	0.26	0.12	0.96
Crude	41	95	1.7	3.5	1.7	14

6.3 NATURAL GAS COMBUSTION

Natural gas is one of the major fuels used throughout the country. As shown in Table 6-1, natural gas is used as an energy source in all four sectors, but the greatest uses are in the

industrial (46 percent) and residential (15 percent) sectors. The five States that consume the largest quantities of natural gas are Texas, California, Louisiana, Illinois, and New York. However, only Louisiana and Oklahoma consume more energy via natural gas combustion than by either coal or petroleum products combustion.²⁵

6.3.1 Natural Gas Characteristics^{31,38}

Natural gas is considered to be a clean fuel. It consists of primarily methane (generally 80 percent or greater by mass), along with varying amounts of ethane, propane, butane, and inert material (typically nitrogen, carbon dioxide, and helium). The average heating value of natural gas is about 8,900 kilocalories per standard cubic meter (kcal/scm) (1,000 Btu per standard cubic foot [Btu/scf]), with levels ranging from 8,000 to 9,000 kcal/scm (900 to 1,100 Btu/scf). No data are available on the mercury content of natural gas. However, concentrations are expected to be quite low. Little mercury is expected to be found in raw gas, and the processing steps used to recover liquid constituents and to remove hydrogen sulfide from the raw gas should remove mercury that is contained in the raw gas.

6.3.2 Process Description³⁸

Natural gas combustion sources can be divided into four categories: utility/large industrial boilers, small industry boilers, commercial boilers, and residential furnaces. These systems are configured differently, but the combustion processes are comparable for all categories. The natural gas and combustion air are mixed in a burner and introduced to a combustion chamber via a flame. The natural gas flame temperature, which exceeds 1000°C (1832°F), will volatilize any mercury or mercury compounds in the fuel. The compounds will then be exhausted as a vapor from the boiler or furnace with the

combustion gas stream. This exhaust stream is the only source of mercury emissions from natural gas combustion.

6.3.3 Emission Control Measures

No control measures applied to natural gas-fired boilers and furnaces are expected to affect mercury emissions.

6.3.4 Emissions

The only source of mercury emissions from natural gas combustion is the combustion gas exhaust stack, and mercury emissions from this source are expected to be minimal. Data on mercury emissions from natural gas combustion are very limited. One reference reported an emission factor of $4.9 \text{ kg}/10^{15} \text{ J}$ ($11.3 \text{ lb}/10^{12} \text{ Btu}$) for both tangential-fired and wall-fired boilers based on emission test data.³⁹ However, this emission factor seems unlikely in that it would require the concentration of mercury in natural gas to be 0.27 ppmwt, a concentration that is of the same order of magnitude as coal and fuel oil. Given the processing steps that natural gas undergoes, this concentration does not seem feasible. Consequently, the emission factor presented above is not considered to be reliable, and no emission factor is recommended for mercury.

6.4 WOOD COMBUSTION

Wood and wood wastes are used as fuel in both the industrial and residential sectors. In the industrial sector, wood waste is fired to industrial boilers to provide process heat, while wood is fired to fireplaces and wood stoves in the residential sectors. The information below includes process descriptions for the three combustion processes (boilers, fireplaces, and wood stoves), descriptions of the control measures used for wood-fired processes, and emission factors.

6.4.1 Process Description^{38,40}

Wood waste combustion in boilers is mostly confined to those industries for which it is available as a byproduct. These boilers generate energy and 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 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. A State of Washington study in 1990 found the mercury content in bark waste to range from <0.08 to 0.84 ppmwt.⁴⁰

As of 1980, approximately 1,600 wood-fired boilers were operating in the U.S., with a total capacity of over 30 gigawatts (GW) (1.0×10^{36} Btu/hr). No specific data on the distribution of these boilers were identified, but most are likely to be located in the Southeast, the Pacific Northwest States, Wisconsin, Michigan, and Maine.

The most common firing method employed for larger wood-fired boilers is the spreader stoker. 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. Natural gas or oil is often fired in spreader stoker boilers as auxiliary fuel to maintain a constant steam supply when the wood waste supply or composition fluctuates. Auxiliary fuel allows more steam to be generated than is possible from the waste supply alone.

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 suspension firing 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.

Wood stoves are commonly used in residences as space heaters, both as the primary source of residential heat and to supplement conventional heating systems. The three different categories of wood stoves are:

- The conventional wood stove;
- The noncatalytic wood stove; and
- The catalytic wood stove.

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 emissions 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's) and carbon monoxide (CO) in

the exhaust gases, thus augmenting their ignition and combustion at normal stove operating temperatures.

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.

All of the systems described above operate at temperatures that are above the boiling point of mercury and mercury compounds. Consequently, any mercury contained in the fuel will be emitted with the combustion gases. The combustion exhaust stack is the only source of mercury emissions from these processes.

6.4.2 Emission Control Measures³⁸

Although some wood stoves use control measures to reduce VOC and CO emissions, these techniques are not expected to affect mercury emissions. However, wood waste boilers do employ PM control equipment, which may provide some reduction. These systems are described briefly below.

Currently, the four most common control devices used to reduce PM emissions from wood-fired boilers are mechanical collectors, wet scrubbers, ESP's, and fabric filters. Of these controls, only the last three have the potential for significant mercury reduction.

The most widely used wet scrubbers for wood-fired boilers are venturi scrubbers. With gas-side pressure drops exceeding 4 kilopascals (15 inches of water), PM collection efficiencies of 90 percent or greater have been reported for venturi scrubbers operating on wood-fired boilers. No data were located on the performance of these systems relative to mercury emissions.

However, some control is expected (probably in the range of 50 to 90 percent) based on results achieved for coal combustion sources.

Fabric filters (i.e., baghouses) and ESP's are employed when PM collection efficiencies above 95 percent are required. Collection efficiencies of 93 to 99.8 percent for PM have been observed for ESP's operating on wood-fired boilers, but mercury efficiencies are likely to be substantially less (probably 50 percent less) based on the performance of ESP's in controlling mercury from coal combustion sources. The performance of ESP's in controlling mercury depends on temperature and the amount of carbon in the fly ash. Fabric filters have had limited applications to wood-fired boilers because of fire hazards. Despite complications, fabric filters are generally preferred for boilers firing salt-laden wood. This fuel produces fine PM with a high salt content for which fabric filters can achieve high collection efficiencies. In two tests of fabric filters operating on salt-laden wood-fired boilers, PM collection efficiencies were above 98 percent. No data are available on mercury emission reduction for fabric filters, but results for other combustion sources suggest that efficiencies will be low, probably 50 percent or less, depending on temperature and the carbon content of the fly ash.

6.4.3 Emissions

The primary source of mercury emissions from wood combustion processes is the combustion gas exhaust stack. Small quantities of mercury also may be emitted with the fugitive PM emissions from bottom and fly ash handling operations.

The data on mercury emissions from wood combustion are quite limited. A recent study to update the wood waste combustion section of AP-42 and a report from the National Council of the Paper Industry for Air and Stream Improvement provided a range

TABLE 6-16. SUMMARY OF MERCURY EMISSION FACTORS FOR WOOD COMBUSTION

Operation	Mercury emission factors			
	10 ⁻³ g/Mg wood burned		10 ⁻⁶ lb/ton wood burned	
	Range	Mean	Range	Mean
Wood waste boiler ^a	1.3-10	3.4	2.6-21	6.7
Residential wood stove-- conventional	--	130	--	260

Source: References 40-42.

^aBased on an assumed heating value of 10,460 kJ/kg (4,500 Btu/lb) and PM control.

and average typical emission factor for wood waste combustion in boilers based on the results of eight tests.^{40,41} Table 6-16 presents the range and average obtained from those tests. The average is recommended as the best typical emission factor for wood waste combustion.

A review of the literature produced one emission factor for residential wood combustion.⁴² This factor, which was based on a single test at one location, is also presented in Table 6-16. Because mercury content in wood may vary with local soil conditions, this single value may not be representative of conditions across the U.S. and should be used cautiously.

6.5 MUNICIPAL WASTE COMBUSTION

Refuse or municipal solid waste (MSW) consists primarily of household garbage and other nonhazardous commercial, institutional, and industrial solid waste. Municipal waste combustor (MWC's) are used to reduce the mass and volume of MSW that ultimately must be landfilled.

Currently, over 160 MWC plants are in operation in the U.S. with capacities greater than 36 megagrams per day (Mg/d) [40 tons per day (ton/d)] and a total capacity of approximately

100,000 Mg/day (110,000 ton/d) of MSW. It is predicted that by 1997, the total MWC capacity will approach 150,000 Mg/day (165,000 ton/d), which represents over 28 percent of the estimated total amount of MSW generated in the U.S. by the year 2000.⁴³ However, because permitting difficulties have delayed construction of new units, these projections may be optimistic. Table 6-17 shows the geographic distribution of MWC units and capacities by States.⁴³

In addition to these large units, a number of smaller, specialized facilities around the U.S. also burn MSW. However, the total nationwide capacity of those smaller units is only a small fraction of the total capacity of units with individual capacities of 36 Mg/d (40 ton/d) and larger.

6.5.1 Municipal Solid Waste Characteristics⁴⁴⁻⁴⁶

Municipal solid waste is a heterogeneous mixture of the various materials found in household, commercial, and industrial wastes. Major constituents in typical municipal waste are listed in Table 6-18. Known sources of mercury in MSW are household and film pack batteries, discarded electrical equipment and wiring, fluorescent bulbs, paint residues, and plastics. As of 1989, 644 Mg (709 tons) of mercury were reported to be discarded in the municipal solid waste stream, and the concentration of mercury in solid waste is reported to be in the range of less than 1 to 6 ppm by weight with a typical value of 4 ppm by weight.^{45,46} However, because of changes in mercury consumption, these concentrations are expected to decrease in the future.^{45,46}

6.5.2 Process Description^{31,43,47}

The three principal MWC classes are mass burn, refuse-derived fuel (RDF), and modular combustors. The paragraphs below briefly describe some of the key design and operating characteristics of these different combustor types. References 31, 43, and 47 provide more detailed process

TABLE 6-17. SUMMARY OF GEOGRAPHICAL DISTRIBUTION OF MWC FACILITIES

State	Number of MWC Facilities	State MWC Capacity Mg/d (ton/d)	Percentage of Total MWC Capacity in the United States
AK	2	150 (170)	<1
AL	2	900 (990)	1
AR	5	350 (380)	<1
CA	3	2,330 (2,560)	2
CT	9	6,050 (6,660)	6
DC	1	910 (1,000)	1
DE	1	550 (600)	<1
FL	14	15,770 (17,350)	16
GA	1	450 (500)	<1
HI	1	2,510 (2,760)	2
IA	1	180 (200)	<1
ID	1	45 (50)	<1
IL	1	1,450 (1,600)	1
IN	1	2,150 (2,360)	2
MA	10	9,400 (10,340)	9
MD	3	3,460 (3,810)	3
ME	4	1,700 (1,870)	2
MI	5	4,380 (4,820)	4
MN	13	4,850 (5,330)	5
MO	1	71 (78)	<1
MS	1	140 (150)	<1
MT	1	65 (72)	<1
NC	4	710 (780)	1
NH	4	780 (860)	1
NJ	6	5,290 (5,820)	5
NY	15	11,370 (12,510)	11
OH	4	4,360 (4,800)	4
OK	2	1,120 (1,230)	1
OR	3	740 (810)	1
PA	6	6,550 (7,200)	6
PR	1	950 (1,040)	1
SC	2	760 (840)	1
TN	4	1,350 (1,480)	1
TX	4	220 (240)	<1
UT	1	360 (400)	<1
VA	9	6,220 (6,840)	6
WA	5	1,360 (1,500)	1
WI	9	1,240 (1,360)	1
Totals	160	101,200 (111,400)	100

Source: Reference 43.

**TABLE 6-18. CURRENT AND FORECAST COMPOSITION OF DISPOSED RESIDENTIAL
AND COMMERCIAL WASTE (WEIGHT PERCENT)**

Component	Year	
	1980	1990
Paper and Paperboard	33.6	38.3
Yard Wastes	18.2	17.0
Food Wastes	9.2	7.7
Glass	11.3	8.8
Metals	10.3	9.4
Plastics	6.0	8.3
Wood	3.9	3.7
Textiles	2.3	2.2
Rubber and Leather	3.3	2.5
<u>Miscellaneous</u>	<u>1.9</u>	<u>2.1</u>
Totals	100.0	100.0

Source: Reference 44.

descriptions and process diagrams for each of the systems described below.

In 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 fed onto a moving grate. Combustion air in excess of stoichiometric amounts is supplied 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 tons/d) of MSW throughput per unit. The mass burn combustor category can be divided into mass burn refractory wall (MB/REF), mass burn/waterwall (MB/WW), and mass burn/rotary waterwall (MB/RC) designs. The two most common, MB/REF and MB/WW, are described below.

The MB/REF combustors are older facilities that comprise several designs. This type of combustor is continuously fed and operates in an excess air mode with both underfire and overfire air provided. The waste is moved on a traveling grate and is not mixed 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 mix 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 grates to a water quench pit for collection and disposal in a landfill. The MB/REF combustors have a refractory-lined combustion chamber and operate at relatively high excess air rates to prevent excessive temperatures, which can result in refractory damage, slagging, fouling, and corrosion problems.

Because of their operating characteristics, the tracking grate systems may have cool ash pockets in which mercury and mercury compounds are not exposed to high temperature and are thereby retained in the ash, rather than being exhausted with the combustion gas stream. Consequently, mercury and mercury compounds may be emitted as fugitive emissions from ash handling. However, the combustion stack is the primary source of mercury emissions. In the rocking and reciprocating grate systems, essentially all mercury will be exhausted with the combustion gas.

The MB/WW design represents the predominant technology in the existing population of large MWC's, and it is expected that over 50 percent of new units will be MB/WW designs. In MB/WW units, the combustor walls are constructed of metal tubes that contain pressurized water and recover radiant energy from the combustion chamber. With this type of system, unprocessed waste (after removal of large, bulky items and noncombustibles) is delivered by an overhead crane to a feed hopper that conveys the waste into the combustion chamber. Nearly all modern MB/WW facilities utilize reciprocating grates or roller grates to move the waste through the combustion chamber. The grates typically include two or three separate sections where designated stages in the combustion process occur. On the initial grate section, referred to as the drying grate, the moisture content of the waste is reduced prior to ignition. In the second grate section, the burning grate, 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. 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 loading area or storage area prior to disposal. Because the waste bed is exposed to fairly uniform high combustion temperatures, mercury and mercury compounds will be exhausted as vapors with the combustion gases.

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-fire 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 (ASTM). 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 feed 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 to allow more time for combustion to be completed on the grate. Bottom ash drops into a water-filled quench chamber. 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. Because essentially all of the waste is exposed to high combustion temperatures on the grate, most of the mercury in the RDF will be discharged with the combustion gas exhaust.

In a fluidized-bed combustor (FBC), fluff or pelletized RDF is combusted in a turbulent bed of noncombustible material, such as limestone, sand, or silica. In its simplest form, the FBC consists of a combustor vessel equipped with a gas distribution

plate and an underfire air windbox at the bottom. The combustion bed overlies the gas distribution plate. The RDF may be injected into or above the bed through ports in the combustor wall. The combustor bed is suspended or "fluidized" through the introduction of underfire air at a high pressure and flow rate. Overfire air is used to complete the combustion process.

Good mixing is inherent in the FBC design. Fluidized-bed combustors have uniform gas temperatures and mass compositions in both the bed and in the upper region of the combustor. This uniformity allows the FBC's to operate at lower excess air and temperature levels than conventional combustion systems. Waste-fired FBC's typically operate at excess air levels between 30 and 100 percent and at bed temperatures around 815°C (1500°F). At this temperature, most mercury and mercury compounds will be volatilized and exhausted with the combustion gas stream as a vapor.

In terms of number of facilities, modular starved- (or controlled-) air (MOD/SA) combustors represent a large segment of the existing MWC population. However, because of their small sizes, they account for only a small percentage 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 intermittently to the primary chamber by a hydraulically activated ram. The charging bin is filled by a front-end loader or by other mechanical systems. 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 lengthy, lasting up to 12 hours. Bottom ash is usually discharged to a wet quench pit.

The quantity of air introduced in the primary chamber defines the rate at which waste burns. Combustion air is introduced in the primary chamber at substoichiometric 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 (1200° to 1800°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 excess 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 to 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 1200° (1800° to 2200°F). At these primary chamber and secondary chamber temperatures, essentially all of the mercury contained in the waste is expected to be emitted as a vapor from the secondary chamber with the combustion gas stream.

6.5.3 Emission Control Measures

Mercury emissions from MWC units are generally controlled by adsorbing the mercury vapors from the combustion chamber onto the acid gas sorbent material and then removing the particle-phase mercury with a high-efficiency PM control device. The PM control devices most frequently used in the U.S. are ESP's and fabric filters. To achieve substantial mercury control, reducing flue gas temperature at the inlet to the control device to 175°C (350°F) or less is beneficial.⁴⁸ Typically, newer MWC systems use a combination of gas cooling and duct sorbent injection (DSI) or spray dryer (SD) systems upstream of the PM device to reduce temperatures and provide a mechanism for acid

gas control. The information contained in Reference 48 suggests that these combined acid gas/PM systems can achieve improved mercury control by injecting sodium sulfide (Na_2S), activated carbon, or modified activated carbon into the flue gas upstream from the DSI or SD unit. The paragraphs below briefly describe the DSI and SD processes. Because the ESP's and FF's used on MWC's are comparable to those used on other combustion systems, they are not described. References 43 and 48 provide more detailed descriptions of the control systems and additional information on the performance of these systems.

Spray drying in combination with either fabric filtration or an ESP is the most frequently used acid gas control technology for MWC's in the United States. Spray dryer/fabric filter systems are more common than SD/ESP systems and are used most on new, large MWC's. In the spray drying process, lime is slurried and then injected into the SD through either rotary atomizer or dual-fluid nozzles. The key design and operating parameters that significantly affect SD acid gas performance are the SD's outlet temperature and lime-to-acid gas stoichiometric ratio. The SD outlet temperature, which affects mercury removal, is controlled by the amount of water in the lime slurry.⁴³

With 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. Alkali in the sorbent (generally calcium) reacts with HCl and SO_2 to form alkali salts (e.g., calcium chloride [CaCl_2] and calcium sulfite [CaSO_3]). Some units also use humidification or other temperature control measures upstream from the collection device. Reaction products, fly ash, and unreacted sorbent are collected with either an ESP or fabric filter.⁴³

Add-on mercury control techniques include the injection of activated carbon or Na_2S into the flue gas prior to the PM control system. In sodium sulfide injection, an Na_2S solution is

sprayed into cooled flue gas (about 200°C [390°F]) prior to the acid gas control device. The reaction of Na₂S and Hg precipitates solid mercuric sulfide (HgS) that can be collected in the PM control device.⁴³ These technologies have not been used commercially on MWC's in the United States, but have been applied to MWC's in Europe, Canada, and Japan, where removal efficiencies have been reported to range from over 50 percent to 90 percent, but concerns have been raised that analytical problems may have caused these efficiencies to be overstated.⁴⁸

Recent test programs using activated carbon and Na₂S injection have been conducted in the United States. For activated carbon injection, mercury removal efficiencies reported generally range from 80 percent to over 95 percent. Other test results show mercury reductions ranging from 50 to over 95 percent, depending on the carbon feed rate, with average outlet Hg concentrations generally ranging from 30 to 200 µg/dscm.^{43,48}

6.5.4 Emissions

The primary source of mercury emissions from municipal waste combustors is the combustion gas exhaust stack. However, small amounts of mercury may be emitted as part of the fugitive PM emissions from fly ash handling, particularly if highly efficient dry control systems are used.

A recent study conducted to update the municipal waste combustion section of AP-42 provided a comprehensive review of the available MWC mercury emission data, which are summarized in Table B-2 of Appendix B. The emission data that are presented in Appendix B are in concentration units rather than emission factors because the study found that most of the test reports contained insufficient process data to generate emission factors.

After reviewing the test data, the authors concluded that the development of emission factors for MWC's, using only the test reports which estimated feed rates, would eliminate data from so many facilities, especially key facilities, that the values derived were not likely to be representative of the entire MWC population. In addition, the subjective nature of the refuse feed rates called into question the validity of the limited data. Consequently, emission factors were developed using the F-factor, which is the ratio of the gas volume of the products of combustion to the heating value of the fuel. This approach, presented in EPA Method 19, requires an F-factor and an estimate of the fuel heating value. For MWC's, the F-factor is 0.257 dscm/MJ (9,570 dscf/10⁶ Btu) (at 0 percent O₂). For all combustor types, except RDF combustors, a heating value of 10,500 kJ/kg (4,500 Btu/lb) refuse was assumed. For RDF combustor units, the processed refuse has a higher heating value, and a heating value of 12,800 kJ/kg (5,500 Btu/lb) was assumed. Overall, these data are representative of average values for MWC's.⁴³

The resultant best typical emission factors for different combinations of combustor and control device are presented in Table 6-19. While this procedure does provide good average emission factors that represent an industry cross section, it should not be used to convert individual data points in Appendix B. The assumed F-factor and waste heating values above may not be appropriate for specific facilities.

6.6 SEWAGE SLUDGE INCINERATORS

Currently about 200 sewage sludge incinerators (SSI's) operate in the United States using one of three technologies: multiple hearth, fluidized-bed, and electric infrared. Multiple hearth units predominate, with over 80 percent of the identified, operating SSI's being of that type. About 15 percent of the SSI's are fluidized-bed combustors; 3 percent are electric

**TABLE 6-19. BEST TYPICAL MERCURY EMISSION FACTORS
FOR MUNICIPAL WASTE COMBUSTORS**

Combustor type	Control status ^a	Typical mercury emission factors	
		g/Mg waste	10 ⁻³ lb/ton waste
Mass burn/waterwall	UN	2.8	5.6
	SD or DSI/FF	1.1	2.2
	SD/ESP	1.6	3.3
	ESP	2.8	5.6
Mass burn/rotary waterwall	SD or DSI/FF	1.1	2.2
Mass burn/refractory wall	UN	2.8	5.6
	ESP	2.8	5.6
	DSI/ESP	2.0	4.0
Refuse-derived fuel-fired	UN	2.8	5.5
	SD/FF	1.4	2.9
	SD/ESP	0.21	0.42
	ESP	2.8	5.5
Modular/excess air	ESP	2.8	5.6
Modular/starved air	UN	2.8	5.6
	ESP	2.8	5.6

Source: Reference 43.

^aUN = uncontrolled, SD = spray dryer, FF = fabric filter, ESP = electrostatic precipitator, DSI = duct sorbent injection.

infrared; and the remainder cofire sewage sludge with municipal solid waste.⁴⁹

Figure 6-1 shows the distribution of sewage sludge incinerators in the United States⁵⁰ Most facilities are located in the Eastern United States, but a substantial number are also located on the West Coast. New York has the largest number of SSI facilities with 33, followed by Pennsylvania and Michigan with 21 and 19, respectively. About 1.5×10^6 Mg (1.6×10^6 tons) of sewage sludge on a dry basis are estimated to be incinerated annually.⁴⁹

Limited data obtained on the mercury content of sewage sludge obtained in the mid 1970's indicated that mercury concentrations in municipal sewage sludge range from 0.1 to 89 ppmwt with a mean value of 7 ppmwt and a median value of 4 ppmwt.¹⁴ Similar data collected by EPA from 42 municipal sewage treatment plants in the early 1970's showed a range of 0.6 to 43 ppmwt, with a mean value of 4.9 ppmwt on a dry solids basis.⁵¹ No more recent data were located during this study, and no information is available on how changes in waste disposal and waste treatment practices may affect these levels.

The sections below provide SSI process descriptions, a discussion of control measures, and a summary of mercury emission factors.

6.6.1 Process Description^{43,49}

Figure 6-2 presents a simplified diagram of the sewage sludge incineration process, which involves two primary steps. The first step in the process of sewage sludge incineration is the dewatering of the sludge. Sludge is generally dewatered until it is about 15 to 30 percent solids. When it is more than 25 percent solids, the sludge will usually burn without auxiliary fuel. After dewatering, the sludge is sent to the incinerator,

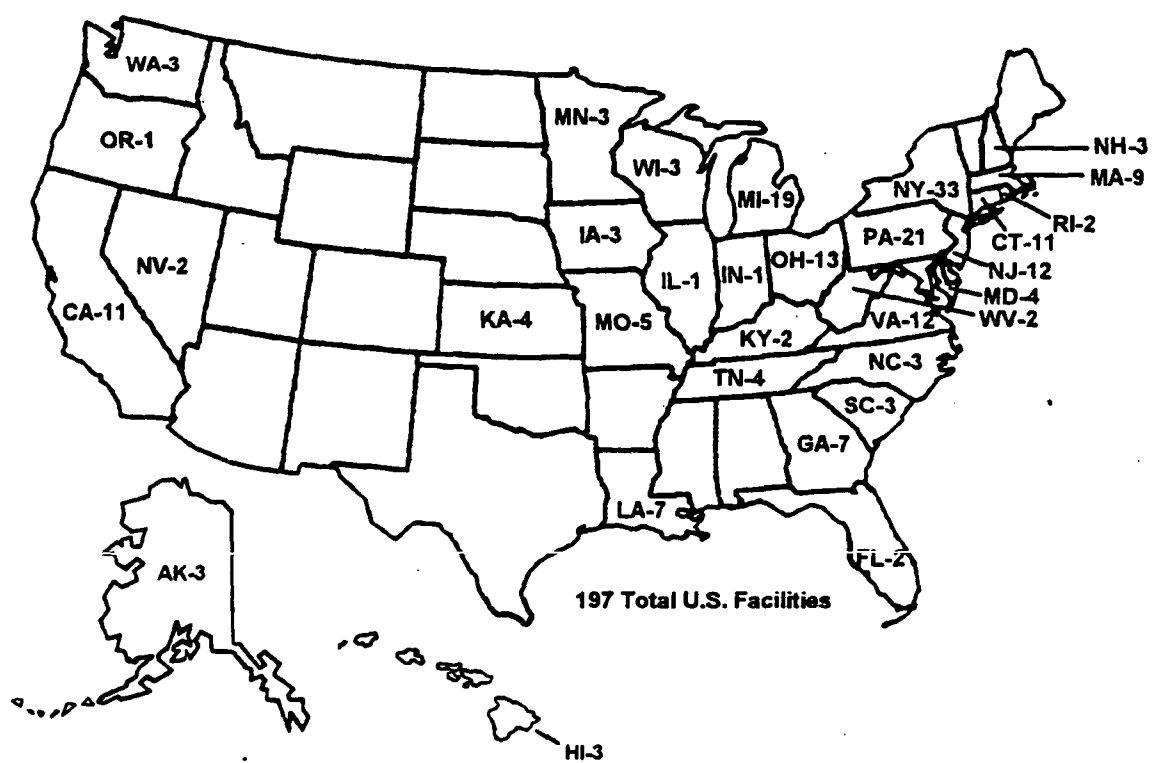
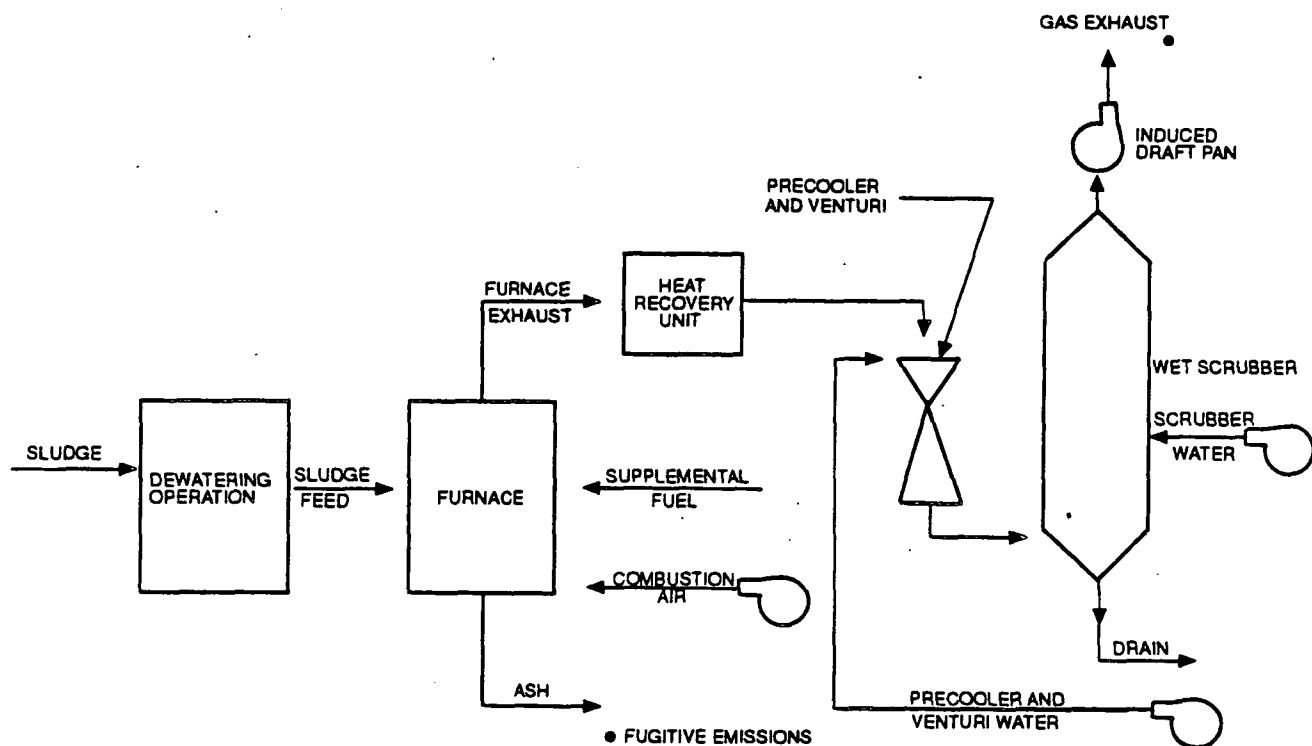


Figure 6-1. Distribution of sewage sludge incinerators in the U.S.⁵⁰



● POTENTIAL SOURCES OF MERCURY EMISSIONS

Figure 6-2. Process flow diagram for sludge incineration.

and thermal oxidation occurs. The unburned residual ash is removed from the incinerator, usually on a continuous basis, and is disposed. A portion of the noncombustible waste, as well as unburned volatile organic compounds, is carried out of the combustor through entrainment in the exhaust gas stream. Air pollution control devices, primarily wet scrubbers, are used to remove the entrained pollutants from the exhaust gas stream. The gas stream is then exhausted, and the collected pollutants are sent back to the head of the wastewater treatment plant in the scrubber effluent. As shown in Figure 6-2, the primary source of mercury emissions from the SSI process is the combustion stack. Some fugitive emissions may be generated from ash handling, but the quantities are expected to be small. Because mercury and mercury compounds are relatively volatile, most mercury will leave the combustion chamber in the exhaust gas; concentrations in the ash residue are expected to be negligible.

The paragraphs below briefly describe the three primary SSI processes used in the United States. References 32 and 49 provide more detailed descriptions and process diagrams.

The basic multiple hearth furnace is cylindrical in shape and is oriented vertically. 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. Attached to the central shaft are the rabble arms with teeth shaped to rake the sludge in a spiral motion, alternating in direction from the outside in, then inside out, between hearths. Typically, the upper and lower hearths are fitted with four rabble arms, and the middle hearths are fitted with two. Cooling air for the center shaft and rabble arms is introduced into the shaft by a fan located at its base. Burners that provide auxiliary heat are located in the sidewalls of the hearths.

Partially dewatered sludge is typically fed onto the perimeter of the top hearth. Typically, the rabble arms move the sludge through the incinerator as the motion of the rabble arms rakes the sludge toward the center shaft, where it drops through holes located at the center of the hearth. This process is repeated in all of the subsequent hearths, with the sludge moving in opposite directions in adjacent hearths. The effect of the rabble motion is to break up solid material to allow better surface contact with heat and oxygen.

Ambient air is first ducted through the central shaft and its associated rabble arms. This air is then taken from the top of the shaft and recirculated onto the lowermost hearth as preheated combustion air. 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.

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 between 815° and 925°C (1500° and 1700°F). When exposed to the temperatures in both upper zones, most mercury will be volatilized and discharged as vapor in the exhaust gas. 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.

Fluidized-bed combustors (FBC's) are cylindrically shaped and oriented vertically. The outer shell is constructed of steel and is 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 rests upon the grid. Partially dewatered sludge is fed into the bed of the

furnace. Air injected through the tuyeres, at pressures from 20 to 35 kPa (3 to 5 psig), simultaneously fluidizes the bed of hot sand and the incoming sludge. Temperatures of 725° to 825°C (1350° to 1500°F), which are sufficient to vaporize most mercury contained in the sludge, are maintained in the bed. As the sludge burns, fine ash particles and mercury vapor are carried out the top of the furnace with the exhaust gas.

An electric incinerator consists 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 incinerators consist of a number of prefabricated modules that are linked together to provide the necessary furnace length. The dewatered sludge cake is conveyed into one end of the incinerator. An internal roller mechanism levels the sludge into a continuous layer approximately 2.5 centimeters (cm) [1 inch (in.)] 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.

6.6.2 Emission Control Measures¹⁴

Most SSI's are equipped with some type of wet scrubbing system for PM control. Because these systems provide gas cooling as well as PM removal, they can potentially provide some mercury control. Limited data obtained on mercury removal efficiencies are presented in the emission factor discussion. The paragraphs below briefly describe the wet scrubbing systems typically used on existing SSI's.

Wet scrubber controls on SSI's range from low pressure drop spray towers and wet cyclones to higher pressure drop venturi scrubbers and venturi/impingement tray scrubber combinations. 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 some 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. Most venturi sections come equipped with variable throats to allow the pressure drop to be increased, thereby increasing PM efficiency. 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 that 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.

6.6.3 Emissions

The primary source of mercury emissions from sewage sludge incineration is the combustion gas exhaust stack. However, small

quantities of mercury also may be emitted with the fugitive PM emissions generated from bottom and fly ash handling operations.

As a part of EPA's development of the mercury NESHAP for SSI's and subsequent review of that NESHAP and as a part of the recent update of AP-42, data have been developed on mercury emissions from SSI's. These data are tabulated in Appendix B, Table B-3 and summarized in Table 6-20.

TABLE 6-20. SUMMARY OF MERCURY EMISSION FACTORS
FOR SEWAGE SLUDGE INCINERATORS

Incinerator type ^a	Control status ^b	No. data points	Mercury emission factors			
			g/Mg dry sludge		10 ⁻³ lb/ton dry sludge	
			Range	Mean	Range	Mean
MH	UN	6	0.54 - 4.6	2.0	1.1-9.2	4.0
MH	IS	2	0.35 - 9.0	0.62	0.70 - 1.8	1.2
MH	VS/IS	1	--	1.1	--	2.1
FB	SC	1	--	24	--	48
FB	VS/IS	3	0.026 - 3.1	0.72	0.052 - 6.2	1.6

Source: References 49 and 51.

^aMH = multiple hearth, FB = fluidized-bed.

^bUN = uncontrolled, IS = impingement scrubber, VS = venturi scrubber, SC = spray chamber.

If the spray chamber on the fluidized-bed unit for which data are given in Table 6-20 is assumed to provide essentially no mercury control, then the uncontrolled emission factors for fluidized-bed and multiple hearth units combined range from 0.54 to 24 g/Mg (1.1 x 10⁻³ to 48 x 10⁻³ lb/ton). This range is consistent with the range of concentrations of mercury in sewage sludge presented earlier (0.1 to 43 ppmwt) for two studies. Because the data on sludge concentrations represent a larger number of facilities than do the test data in Table 6-20, a best typical emission factor of 5.0 g/Mg dry solids (10 x 10⁻³ lb/ton dry solids) was selected. This emission factor is based on a

typical sludge concentration of 5.0 ppmwt and the assumption that all mercury in the sludge is emitted from the incinerator.

Limited data presented in Reference 38 indicate that the impingement scrubbers, venturi scrubbers, and venturi/impingement scrubber combinations have efficiencies in the range of 68 to 96 percent. These ranges are consistent with the data contained in Table 6-20. Consequently, the best typical controlled emission factor was obtained by applying this range to the uncontrolled emission factor reported earlier. The resultant emission factor range is reported in Table 6-21.

TABLE 6-21. BEST TYPICAL MERCURY EMISSION FACTORS FOR SEWAGE SLUDGE INCINERATORS

Control status	Typical mercury emission factors	
	g/Mg dry sludge	10 ⁻³ lb/ton dry sludge
Uncontrolled	5.0	10
Venturi scrubber, impinger scrubber, or combination	0.2-1.6	0.4 - 3.2

The emission factors in Table 6-21 should be used cautiously in that available data suggest that both mercury concentrations in sludge and control efficiencies vary widely. Because mercury emissions from SSI's are regulated by a NESHAP, all SSI's are required to report their compliance status and mercury emission rate annually. Hence, the best source of emission data for an individual facility is the annual compliance status report, which is available through EPA's Compliance Data System.

6.7 MEDICAL WASTE INCINERATION

Medical waste includes infectious and noninfectious wastes generated by a variety of facilities engaged in medical care, veterinary care, or research activities such as hospitals, clinics, doctors' and dentists' offices, nursing homes, veterinary clinics and hospitals, medical laboratories, and

medical and veterinary schools and research units. Medical waste is defined by the U. S. EPA as "any solid waste which is generated in the diagnosis, treatment, or immunization of human beings or animals, in research pertaining thereto, or in the production or testing of biologicals." A medical waste incinerator (MWI) is any device that burns such medical waste.⁵²

Recent estimates developed by EPA suggest that about 3.06 million Mg (3.36 million tons) of medical waste are produced annually in the United States. Approximately 5,000 MWI's, which are distributed geographically throughout the United States, are used to treat this waste. Of these 5,000 units, about 3,000 are located at hospitals; about 150 are larger commercial facilities; and the remainder are distributed among veterinary facilities, nursing homes, laboratories, and other miscellaneous facilities.⁵³

Available information indicates that these MWI systems can be significant sources of mercury emissions. Mercury emissions result from mercury-bearing materials contained in the waste. Although concentrations of specific metals in the waste have not been fully characterized, known mercury sources include batteries; fluorescent lamps; high-intensity discharge lamps (mercury vapor, metal halide, and high-pressure sodium); thermometers; special paper and film coatings; and pigments. Batteries, primarily alkaline and mercury-zinc batteries, are a major mercury source. Mercury is used in alkaline batteries, which are used in digital thermometers, but this use is declining. Mercury-zinc batteries are used in transistorized equipment, hearing aids, watches, calculators, computers, smoke detectors, tape recorders, regulated power supplies, radiation detection meters, scientific equipment, pagers, oxygen and metal monitors, and portable electrocardiogram monitors. Cadmium-mercury pigments are primarily used in plastics but are also used in paints, enamels, printing inks, rubber, paper, and painted textiles.^{45,54} All of these materials can be routed to

an MWI, thereby contributing to mercury emissions from this source category.

6.7.1 Process Description

Although the ultimate destination of almost all medical waste produced in the United States is a solid waste landfill, the waste generally must be treated before it can be landfilled. The primary functions of MWI facilities are to render the waste biologically innocuous and to reduce the volume and mass of solids that must be landfilled by combusting the organic material contained in the waste. Over the years, a wide variety of MWI system designs and operating practices have been used to accomplish these functions. To account for these system differences, a number of MWI classification schemes have been used in past studies, including classification by waste type (pathological, mixed medical waste, red bag waste, etc.), classification by operating mode (continuous, intermittent, batch), and classification by combustor design (retort, fixed-hearth, pulsed-hearth, rotary kiln, etc.). Some insight into MWI processes, emissions, and emissions control is provided by each of these schemes. However, because the available evidence suggests that mercury emissions are affected primarily by waste characteristics, the characterization and control of mercury emissions from MWI's can be discussed without considering other MWI design and operating practices in detail. The paragraphs below provide a generic MWI process description and identify potential sources of mercury emissions. More detailed Descriptions of specific MWI design and operating practices can be found in References 55 through 57.

A schematic of a generic MWI system that identifies the major components of the system is shown in Figure 6-3. As indicated in the schematic, most MWI's are multiple-chamber combustion systems that comprise primary, secondary, and possibly tertiary chambers. The primary components of the MWI process are

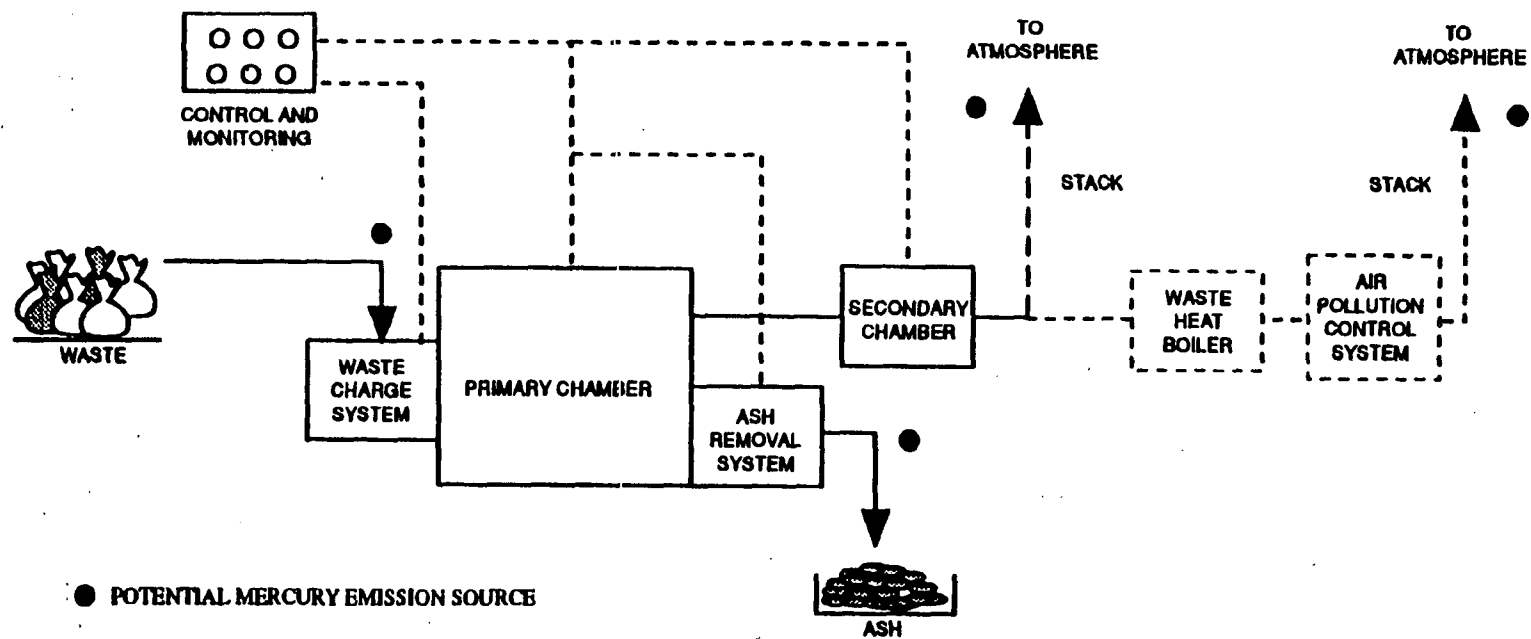


Figure 6-3. Major components of an incineration system.

the waste-charging system, the primary chamber, the ash handling system, the secondary chamber, and the air pollution control system, which are discussed briefly below.

Medical waste is introduced to the primary chamber via the waste-charging system. The waste can be charged either manually or mechanically. With manual charging, which is used only on batch and smaller (generally older) intermittent units, the operator opens a charge door on the side of the primary chamber and tosses bags or boxes of waste into the unit. When mechanical feed systems are employed, some type of mechanical device is used to charge the waste to the incinerator. The most common mechanical feed system is the hopper/ram assembly. In a mechanical hopper/ram feed system, the following steps take place: (1) waste is placed into a charging hopper manually, and the hopper cover is closed; (2) a fire door isolating the hopper from the incinerator opens; (3) the ram moves forward to push the waste into the incinerator; (4) the ram reverses to a location behind the fire door; (5) after the fire door closes, a water spray cools the ram, and the ram retracts to the starting position; and (6) the system is ready to accept another charge. The entire hopper/ram charging sequence normally functions as a controlled, automatically-timed sequence to eliminate overcharging. The sequence can be activated by the operator or for larger, fully automated incinerators, it may be activated at preset intervals by an automatic timer.^{56,57}

The potential for mercury emissions from the waste-charging systems is low. Mechanical systems are generally operated with a double-door system to minimize fugitive emissions. Small quantities of fugitive emissions may be generated while the chamber door is open during manual charging, but no data are available on the magnitude of these emissions.

The primary chamber (sometimes called the "ignition" chamber) accepts the waste and begins the combustion process.

Most modern MWI's operate this chamber in a "controlled-air" mode to maintain combustion air levels at or below stoichiometric requirements. The objectives of this controlled-air operation are to provide a more uniform release of volatile organic materials to the secondary chamber and to minimize entrainment of solids in these off-gases. Three processes occur in the primary chamber. First, the moisture in the waste is volatilized. Second, the volatile fraction of the waste is vaporized, and the volatile gases are directed to the secondary chamber. Third, the fixed carbon remaining in the waste is combusted.

The primary chamber generates two exhaust streams--the combustion gases that pass to the secondary chamber and the solid ash stream that is discharged. Any metal compounds in the waste, including mercury, are partitioned to these two streams in one of three ways. The metals may be retained in the primary chamber bottom ash and discharged as solid waste; they may be entrained as PM in the combustion gases; or they may be volatilized and discharged as a vapor with the combustion gases. Because mercury and mercury compounds are generally quite volatile and because the primary chamber typically operates in the range of 650° to 820°C (1200° to 1500°F), most of the mercury in the waste stream will be exhausted as a vapor to the secondary chamber.

The primary chamber bottom ash, which may contain small amounts of mercury or mercury compounds, is discharged via an ash removal system and transported to a landfill for disposal. The ash removal system may be either manual or mechanical. Typically, batch units and smaller intermittent units employ manual ash removal. After the system has shut down and the ash has cooled, the operator uses a rake or shovel to remove the ash and place it in a drum or dumpster. Some intermittent-duty MWI's and all continuously operated MWI's use a mechanical ash removal system. The mechanical system includes three major components: (1) a means of moving the ash to the end of the incinerator hearth--usually an ash transfer ram or series of transfer rams,

(2) a collection device or container for the ash as it is discharged from the hearth, and (3) a transfer system to move the ash from the collection point. Generally, these automatic systems are designed to minimize fugitive emissions. For example, one type of collection system uses an ash bin sealed directly to the discharge chute or positioned within an air-sealed chamber below the hearth. A door or gate that seals the chute is opened at regular intervals to allow the ash to drop into the collection bin. When the bin is filled, the seal-gate is closed, and the bin is removed and replaced with an empty bin. In another system, the ash is discharged into a water pit. The ash discharge chute is extended into the water pit so that an air seal is maintained. The water bath quenches the ash as the ash is collected. A mechanical device, either a rake or drag conveyor system, is used to intermittently or continuously remove the ash from the quench pit. The excess water is allowed to drain from the ash as it is removed from the pit, and the wetted ash is discharged into a collection container.

The potential for mercury emissions from both mechanical and manual ash discharge systems is minimal. As described above, most mechanical systems have seals and provide ash wetting as described above to minimize fugitive PM emissions. While manual systems can generate substantial fugitive PM, the concentrations of mercury have generally been shown to be quite low.⁵⁸ Consequently, fugitive mercury emissions are negligible.

Almost all the mercury that enters the primary chamber is exhausted to the secondary chamber as a vapor. The primary function of the secondary chamber is to complete the combustion of the volatile organic compounds that was initiated in the primary chamber. Because the temperatures in the secondary chamber are typically 980°C (1800°F) or greater, essentially all of the mercury that enters the secondary chamber will be exhausted as a vapor. The hot exhaust gases from the secondary chamber may pass through an energy recovery device (waste heat

boiler or air-to-air heat exchanger) and an air pollution control system before they are discharged to the atmosphere through the combustion stack. This combustion stack is the major route of mercury emissions from MWI's.

6.7.2 Emission Control Measures

A number of air pollution control system configurations have been used to control PM and gaseous emissions from the MWI combustion stacks. Most of these configurations fall within the general classes of wet systems and dry systems. Wet systems typically comprise a wet scrubber designed for PM control (venturi scrubber or rotary atomizing scrubber) in series with a packed-bed scrubber for acid gas removal and a high-efficiency mist elimination system. Most dry systems use a fabric filter for PM removal, but ESP's have been installed on some larger MWI's. These dry systems may use sorbent injection via either dry injection or spray dryers upstream from the PM device to enhance acid gas control. Because these systems are designed primarily for PM and acid gas control, they have limitations relative to mercury control. However, recent EPA studies indicate that sorbent injection/fabric filtration systems can achieve improved mercury control by adding activated carbon to the sorbent material. More detailed descriptions of MWI air pollution control systems can be found in Reference 58. The emission data presented in the section below provide information on the performance of some of the more common systems.

6.7.3 Emissions⁵⁹⁻⁷²

The primary source of emissions from medical waste incineration is the combustion gas exhaust stack. However, small quantities of mercury may be contained in the fugitive PM emissions from ash handling operations, particularly if the fly ash is collected in a dry air pollution control system with high mercury removal efficiencies.

Over the past 5 years, mercury emissions have been measured at several MWI's through the U. S. EPA's regulatory development program, MWI emission characterization studies conducted by the State of California, and compliance tests conducted in response to State air toxic requirements. Emission data from approximately 20 MWI's were identified in developing this L&E document. However, only the data from 14 facilities were considered adequate for emission factor development. For the other facilities, either process data were insufficient to develop emission factors or the test methodologies were considered unacceptable. Emission data for the 14 facilities are tabulated in Appendix B, Table B-4. The paragraphs below summarize the information on uncontrolled emissions and on the performance of emission control systems collected from these 14 facilities.

The uncontrolled emission data collected at eight facilities show wide variability, with mercury emission factors ranging from 0.043 to 317 g/Mg of waste charged (8.6×10^{-4} to 6.3×10^{-1} lb/ton). These data represent a variety of waste types (mixed medical waste, red bag [infectious] waste only, and pathological waste) and incinerator types (continuous and intermittent units with varied operating practices). While the data are insufficient to demonstrate a direct relationship between waste characteristics and emissions, the data strongly suggest that most of this variability is related to differences in the mercury content of the waste. First, characterization of the bottom ash at several facilities showed virtually no mercury in the ash, indicating that the mercury in the waste is discharged with the combustion gases. Second, as part of an EPA study, wastes from two different hospitals were fired to the same incinerator under comparable operating conditions. The average emission factors for the two wastes varied by over an order of magnitude with wastes from the smaller hospital yielding an emission factor of 1 g/Mg (2.2×10^{-3} lb/ton) and those from the larger hospital yielding a factor of 66 g/Mg (1.3×10^{-1} lb/ton),

again providing evidence of substantial waste-related variation. Although there has been some speculation that the higher emission factors result from having mercury-bearing items, such as batteries and disposable thermometers in the waste stream, insufficient information is available to define conclusively the influence of waste attributes on mercury emissions.

Because emissions are strongly related to waste characteristics, separate uncontrolled emission factors were developed for the different waste types. These emission factors are summarized in Table 6-22. Substantially greater information is available for mixed medical waste incineration than for either red bag or pathological waste incineration. Consequently, the mixed waste results are considered to be a more reliable indicator of the range of emission factors likely to be found across the MWI population than are the red bag or pathological results. However, because the range in emission factors is so large, even the mixed waste emission factors should be applied to individual MWI's with caution. In particular, the average emission factor of 50 g/Mg (1.1×10^{-1} lb/ton) is strongly influenced by the largest emission factor identified (317 g/Mg [6.3×10^{-1} lb/ton]), which is a factor of 5 larger than the second largest value. If the largest and smallest values are removed, the trimmed mean is 20 g/Mg (4.0×10^{-2} lb/ton), which is of the same order of magnitude as the median of the data. Hence, the emission factor of 20 g/Mg (4.0×10^{-2} lb/ton) is recommended as the best emission factor for a typical MWI firing mixed medical waste.

The emission factors for the red bag and pathological waste should be used with extreme caution because each factor is based on results from waste fired at only one facility. Two observations are noteworthy in interpreting these data. First, the red bag emission factor of 16 g/Mg (3.2×10^{-2} lb/ton) is at the upper end of the range of emission factors. However, the wastes were generated by the same facility that had the largest

**TABLE 6-22. SUMMARY OF UNCONTROLLED MERCURY EMISSION FACTORS
FOR MEDICAL WASTE INCINERATORS**

Waste type	No. of facilities	No. of test runs	Mercury emission factors, g/Mg (10^{-3} lb/ton) waste	
			Range	Mean
Mixed ^{a,b}	9	54	0.043 - 317 (0.086 - 634)	50.4 (101)
Red bag	1	10	10 - 27 ^c (20 - 54)	16 (32)
Pathological	1	6	d	0.5 (1.0)

Source: References 59-67 and 70.

^aBased on the range of facility averages. Number of runs for each facility ranged from two to nine.

^bThis emission factor is strongly influenced by a single large value. A better estimate of emissions from a "typical" facility is the trimmed mean, which is 20 g/Mg (40×10^{-2} lb/ton).

^cBased on the range spanned by three test averages (two tests comprised three runs; one test comprised four runs) at one facility.

^dThe two tests (three runs each) resulted in the same emission factor. A range could not be determined.

mixed waste emission factor, so the high factor may be misleading. Similarly, the emission factor for pathological waste of 0.5 g/Mg (1.0×10^{-3} lb/ton) is at the bottom end of the mixed waste range. However, this low emission factor also may be misleading because tests at the same facility produced the lowest mixed waste emission factor. As evidenced by these observations, the red bag and pathological emission data are too sparse to differentiate between the effects of waste type and facility-specific waste practices on mercury emissions.

Substantially fewer data are available on controlled emissions than on uncontrolled emissions.^{61,62,66-72} The best data available are those generated by the U. S. EPA to characterize the performance of three MWI air pollution control systems--a venturi scrubber/packed-bed system, a dry injection/fabric filter system, and a spray dryer/fabric filter system. Table 6-23 presents controlled emission factors, mercury emission control efficiencies, and flue gas temperatures for these air pollution control systems. Because controlled emission factors could only be developed for a few facilities, they are not likely to represent the variability across the incinerator population. Therefore, it is recommended that controlled emission factors be developed by applying the average control efficiencies to uncontrolled emission factors or emission rates rather than using the controlled emission factors presented in Table 6-23.

The performances of the dry systems were examined with and without carbon injection. The results from these tests are also presented in Table B-4, Appendix B. These results indicate that the two dry systems without carbon injection provided essentially no control of mercury. For these systems, the outlet mercury emissions range from 400 percent higher to 40 percent lower than the inlet emissions, depending on the flue gas temperature. This variability is considered to be within the normal range of process and emission test method variability as described in

TABLE 6-23. SUMMARY OF CONTROLLED MERCURY EMISSION FACTORS AND CONTROL EFFICIENCIES FOR MEDICAL WASTE INCINERATORS

Waste type ^a	Control status ^b	No. of facilities	No. of runs	Mercury emission factors ^c				Control efficiency, % ^d		Flue gas temp. °F	
				g/Mg waste		10 ⁻³ lb/ton waste					
				Mean	Range	Mean	Range	Mean	Range	Mean	Range
M	VS/PB	4	11	5.4	0.72-20	11	1.4-40	8.0	-52-62 ^e	186	120-301
	DI/ESP	1	3	9.0	2.7-17	18	5.5-33	NA	NA	402	309-405
	DI/FF	1	9	50	20-110	100	17-220	20	-18-70	299	289-307
	DI/FF + C	1	5	4.2	0.74-6.4	8.3	1.5-13	91	85-98	291	282-295
	SD/FF	1	3	24	8.3-49	48	17-98	38	25-51	285	--
	SD/FF + C	1	3	4.0	1.5-6.1	8.0	3.0-12	90	84-96	282	270-289
RB	DI/FF	1	9	26	2.6-84	52	5.2-170	-76	-400-45	314	305-321

Source: References 61, 62, and 66-72.

^aM = mixed medical waste, RB = red bag waste.

^bVS = venturi scrubber, PB = packed bed scrubber, DI = dry injection

ESP = electrostatic precipitator, FF = fabric filter, C = carbon injection, SD = spray dryer.

^cRanges are for individual runs. Averages were obtained by taking the arithmetic mean of facility averages.

^dNA = not available.

^eEfficiency data were available for only one facility.

Section 9. Consequently, the results are consistent with no measured removal by the control system. However, the dry systems with carbon injection can achieve mercury removal efficiencies in the range of 90 to 95 percent.

The emission test results for the wet systems are also presented in Table B-4, Appendix B. As shown in Table 6-23, the performance of the wet systems in controlling mercury emissions was comparable to that achieved by the dry system without carbon injection. Similar to dry systems, the performance of the wet systems is directly related to flue gas temperature. It is also dependent on the blowdown rate, with efficiency falling if the system approaches equilibrium. The only control systems that provided any degree of control of mercury emissions were the dry systems with carbon injection. Table 6-24 presents the best typical uncontrolled emission factors for MWI's. To obtain best typical controlled emission factors for systems with controls other than dry injection with carbon addition, use these emission factors. For dry systems with carbon injection, apply a 90-percent efficiency to these uncontrolled emission factors.

TABLE 6-24. BEST TYPICAL UNCONTROLLED MERCURY EMISSION FACTORS FOR MEDICAL WASTE INCINERATORS

Waste type	Typical mercury emission factors	
	g/Mg waste	10 ⁻³ lb/ton waste
Mixed	20	40
Red Bag	16	32
Pathological	0.5	1

SECTION 7

EMISSIONS FROM MISCELLANEOUS SOURCES

Mercury has been found to be emitted from various miscellaneous sources including the following:

1. Portland cement manufacturing,
2. Lime manufacturing,
3. Carbon black production,
4. Byproduct coke production,
5. Primary lead smelting,
6. Primary copper smelting,
7. Petroleum refining,
8. Oil shale retorting, and
9. Geothermal power plants.

Raw materials processed at the facilities listed above include minerals, ores, and crudes extracted from the earth. . Many of these raw materials contain mercury. At various stages of processing, the raw materials are heated. Therefore, each of the manufacturing processes listed above may emit mercury during various steps of raw materials processing. This section presents process information, air pollution control measures, and estimates of mercury emissions for these sources.

7.1 PORTLAND CEMENT MANUFACTURING⁷³⁻⁷⁶

More than 30 raw materials are used to manufacture portland cement. These materials can be classified into four basic classes of raw materials: calcareous, siliceous, argillaceous, and ferriferous. Two processes, the wet and dry processes, can be used to manufacture portland cement. In 1990, there were a total of 212 U.S. cement kilns with a combined total clinker capacity of 73.5×10^6 Mg (81.1×10^6 tons). Of this total, 11 kilns with a combined capacity of 1.8×10^6 Mg (2.0×10^6 tons)

were inactive. The total number of active kilns was 201 with a clinker capacity of 71.8×10^6 Mg (79.1×10^6 tons). The name, location, and clinker capacity of each kiln is presented in Appendix C. Based on 1990 U.S. cement kiln capacity data, an estimated 68 percent of the portland cement is manufactured using the dry process, and the remaining 32 percent based on the wet process. A description of the processes used to manufacture portland cement and the emissions resulting from the various operations is presented below.

7.1.1 Process Description

Figure 7-1 presents a basic flow diagram of the portland cement manufacturing process. The process can be divided into four major steps: raw material acquisition and handling, kiln feed preparation, pyroprocessing, and finished cement grinding.

The initial step in the production of portland cement manufacturing is raw materials acquisition. Calcium, which is the element of highest concentration in portland cement, is obtained from a variety of calcareous raw materials, including limestone, chalk, marl, sea shells, aragonite, and an impure limestone known as "natural cement rock." The other raw materials--silicon, aluminum, and iron--are obtained from ores and minerals, such as sand, shale, clay, and iron ore. Mercury is expected to be present in the ores and minerals extracted from the earth. The only potential source of mercury emissions from raw material acquisition would be due to wind blown mercury-containing particulate from the quarry operations. Mercury emissions are expected to be negligible from these initial steps in portland cement production.

The second step involves preparation of the raw materials for pyroprocessing. Raw material preparation includes a variety of blending and sizing operations designed to provide a feed with appropriate chemical and physical properties. The raw material

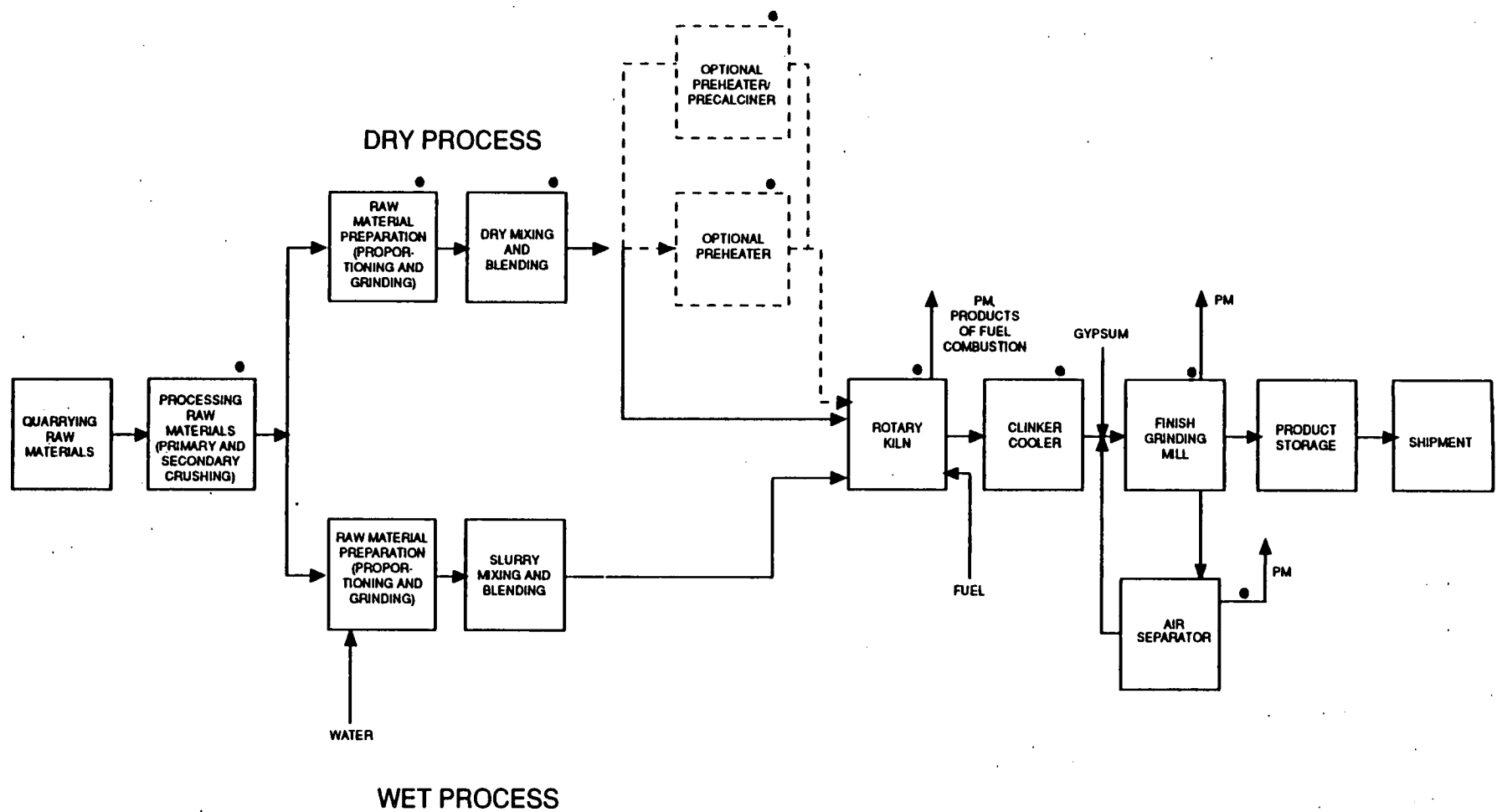


Figure 7-1. Process flow diagram of portland cement manufacturing process.⁷³

processing differs somewhat for wet- and dry-process. At facilities where the dry process is used, the moisture content in the raw material, which can range from less than 1 percent to greater than 50 percent, is reduced to less than 1 percent. Mercury emissions can occur during this drying process but are anticipated to be very low because the drying temperature is much below the boiling point of mercury. At some facilities, heat for drying is provided by the exhaust gases from the pyroprocessor. At facilities where the wet process is used, water is added to the raw material during the grinding step, thereby producing a pumpable slurry containing approximately 65 percent solids.

Pyroprocessing (thermal treatment) of the raw material is carried out in the kiln, which is the heart of the portland cement manufacturing process. During pyroprocessing, the raw material is transformed into clinkers, which are gray, glass-hard, spherically-shaped nodules that range from 0.32 to 5.1 cm (0.125 to 2.0 in.) in diameter. The chemical reactions and physical processes that take place during pyroprocessing include:

1. Evaporation of uncombined water from raw materials as material temperature increases to 100°C (212°F),
2. Dehydration as the material temperature increases from 100°C to approximately 430°C (800°F) to form the oxides of silicon, aluminum, and iron,
3. Calcination, during which carbon dioxide (CO₂) is evolved, between 900°C (1650°F) and 982°C (1800°F) to form calcium oxide,
4. Reaction of the oxides in the burning zone of the rotary kiln to form cement clinker at temperatures about 1510°C (2750°F).

The rotary kiln is a long, cylindrical, slightly inclined, refractory-lined furnace. The raw material mix is introduced into the kiln at the elevated end, and the combustion fuels are usually introduced into the kiln at the lower end, in a countercurrent manner. The rotary motion of the kiln transports the raw material from the elevated end to the lower end. Fuel such as coal or natural gas, or occasionally oil, is used to provide energy for calcination. Mercury is present in coal and oil. Tables 6-4 and 6-11 presented data pertaining to mercury content in coal and oil, respectively. Use of other fuels, such as chipped rubber, petroleum coke, and waste solvents, is becoming increasingly popular. Combustion of fuel during the pyroprocessing step contributes to potential mercury emissions. Mercury may also be present in the waste-derived fuel mentioned above. Because mercury evaporates at approximately 350°C (660°F), most of the mercury present in the raw materials can be expected to be volatilized during the pyroprocessing step. Since temperature at the inlet to the air pollution control device generally do not exceed this temperature, at least a portion of the condensed mercury should be captured with the particulate emissions.

Pyroprocessing can be carried out using one of five different processes: wet process, semi-dry, dry process, dry process with a preheater, and dry process with a preheater/precalciner. These processes essentially accomplish the same physical and chemical steps described above. The last step in the pyroprocessing is the cooling of the clinker. This process step recoups up to 30 percent of the heat input to the kiln system, locks in desirable product qualities by freezing mineralogy, and makes it possible to handle the cooled clinker with conventional conveying equipment. Finally, after the cement clinker is cooled, a sequence of blending and grinding operations is carried out to transform the clinker into finished portland cement.

7.1.2 Emission Control Measures

With the exception of the pyroprocessing operations, the emission sources in the portland cement industry can be classified as either process emissions or fugitive emissions. The primary pollutants resulting from these fugitive sources are PM. The control measures used for these fugitive dust sources are comparable to those used throughout the mineral products industries.

Methods used to reduce particulate levels in the ambient air due to vehicular traffic include paving and road wetting. Additional methods that are applied to other open dust sources include water sprays with and without surfactants, chemical dust suppressants, wind screens, and process modifications to reduce drop heights or enclose storage operations.

Process fugitive emission sources include materials handling and transfer, raw milling operations in dry process facilities, and finish milling operations. Potential mercury emission sources are indicated in Figure 7-1 by solid circles. Typically, particulate emissions from these processes are captured by a ventilation system with a fabric filters. Because the dust from these units is returned to the process, they are considered to be process units as well as air pollution control devices. The industry uses shaker, reverse air, and pulse jet filters, as well as some cartridge units, but most newer facilities use pulse jet filters. For process fugitive operations, the different systems are reported to achieve typical outlet PM loadings of 45 milligrams per cubic meter mg/m^3 (0.02 grains per actual cubic foot [gr/acf]). Because the mercury is in particle form, the performance of these systems relative to mercury control is expected to be equivalent to this overall particulate performance. However, no data are available on mercury performance of fugitive control measures.

In the pyroprocessing units, PM emissions are controlled by fabric filters (reverse air, pulse jet, or pulse plenum) and ESP's. The reverse air fabric filters and ESP's typically used to control kiln exhausts are reported to achieve outlet PM loadings of 45 mg/m^3 (0.02 gr/acf). Clinker cooler systems are controlled most frequently with pulse jet or pulse plenum fabric filters. A few gravel bed (GB) filters have been used on clinker coolers.

According to MacMann, limited data indicate that ESP's capture about 25 percent and baghouses capture up to 50 percent of the potential mercury emissions as particulate.⁷⁷ If this cement kiln dust (CKD) is returned to the process, the mercury or mercury compounds in the dust are volatilized again and therefore essentially all of the mercury input to the process eventually leaves as a vapor in the kiln stack. If the dust is wasted, 25 to 50 percent of the mercury input to the process escapes as a solid in the CKD with the remaining 50 to 75 percent escaping as a vapor in the kiln stack.⁷⁷ Some levels of mercury have been detected in the portland cement product.⁷⁶

7.1.3 Emissions

The principal sources of mercury emissions are expected to be from the kiln and preheating/precalcining steps. Negligible quantities of emissions would be expected in the raw material processing and mixing steps because the only source of mercury would be fugitive dust containing naturally occurring quantities of mercury compounds in the limestone. Processing steps that occur after the calcining process in the kiln would be expected to be a much smaller source of emissions than the kiln. Potential mercury emission sources are denoted by solid circles in Figure 7-1. Emissions resulting from all processing steps include particulate matter. Additionally, emissions from the pyroprocessing step include other products of fuel combustion such as sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon

dioxide (CO_2), and carbon monoxide (CO). Carbon dioxide from the calcination of limestone will also be present in the flue gas.

Cement kiln test reports were reviewed for facilities performing Certification of Compliance (COC) tests required of all kilns burning waste derived fuel (WDF). Fifteen of the test reports contained sufficient process information to allow calculation of mercury emission factors for the kiln stack; these data are shown in Appendix C, Table C-2. The results from these 15 kilns showed a range in average emission factors from 2.23×10^{-3} g/Mg of clinker (4.5×10^{-6} lb/ton of clinker) to 0.49 g/Mg of clinker (9.7×10^{-4} lb/ton of clinker). The average emission factor for all 15 facilities was 8.7×10^{-2} g/Mg of clinker (1.7×10^{-4} lb/ton of clinker). These data are based on the average of all test runs.

7.2 LIME MANUFACTURING

Lime is produced in various forms, with the bulk of production yielding either hydrated lime or quicklime. In 1992, producers sold or used 16.4×10^6 Mg (18×10^6 tons) of lime produced at 113 plants in 32 States and Puerto Rico. The 1992 production represented a 4 percent increase over 1991 production. In 1989, there were 116 lime production operations in the U.S. with a annual production of 15.56×10^6 Mg (17.15×10^6 tons).⁷⁸ The leading domestic uses for lime include steelmaking, flue gas desulfurization, pulp and paper manufacturing, water purification, and soil stabilization.⁷⁸

Appendix C provides a list of the active lime plants in the United States in 1991. The list includes company headquarters' locations, plant locations by State, and the type of lime produced at each plant. The geographical locations by State of the lime operations are shown in Table 7-1.

TABLE 7-1. LIME PRODUCERS IN THE UNITED STATES IN 1989

State	No. of Plants	State	No. of Plants
Alabama	5	Michigan	8
Arizona	3	Minnesota, Montana	7 ^a
Arkansas, Louisiana, Oklahoma	3 ^a	North Dakota	3
California	11	Ohio	9
Colorado, Nevada, Wyoming	9 ^a	Pennsylvania	10
Hawaii, Oregon, Washington	4 ^a	Texas	8
Idaho	3	Utah	4
Illinois, Indiana, Missouri	8 ^a	Virginia	5
Iowa, Nebraska, South Dakota	4 ^a	Wisconsin	4
Kentucky, Tennessee, West Virginia	5 ^a		
Massachusetts	2	Puerto Rico	1

Source: Reference 78.

^aTotal for States listed.

7.2.1 Process Description⁷³

Lime is produced by calcining (removal of CO_2) limestone at a high temperature. The product of the calcining operation is quicklime; this material can be hydrated with water to produce hydrated lime or slaked lime ($\text{Ca}(\text{OH})_2$). Figure 7-2 presents a flow diagram for the lime manufacturing process. Lime manufacturing is carried out in five major steps. These are:

1. Quarrying raw limestone,
2. Preparing the limestone for calcination,
3. Calcining the limestone,
4. Processing the lime by hydrating, and
5. Miscellaneous transfer, storage, and handling processes.

The manufacturing steps in lime production are very similar to that of the dry portland cement process, which was discussed in the previous section. The most important process step with respect to emissions of mercury and other air pollutants is the calcination. During calcination, kiln temperature may reach 1820°C (3300°F). Approximately 90 percent of the lime produced in the United States is manufactured by calcining limestone in a rotary kiln. Other types of lime kilns include the vertical or shaft kiln, rotary hearth, and fluidized bed kilns. Fuel, such as coal, oil, petroleum coke, or natural gas, may be used to provide energy for calcination. Petroleum coke is usually used in combination with coal. Auxiliary fuels such as chipped rubber and waste solvents may potentially be used; at the present time, however, no lime kilns use these auxiliary fuels.

Mercury is expected to be present in very small quantities in the limestone and in coal and oil used as fuel. Tables 6-4 and 6-11 present data pertaining to the mercury content in coal and oil, respectively. The predominant fuel sources for lime kilns are coal, coal/petroleum coke, and natural gas; oil is rarely used as a fuel source. As with the production of portland cement, any mercury present in the raw materials can be expected

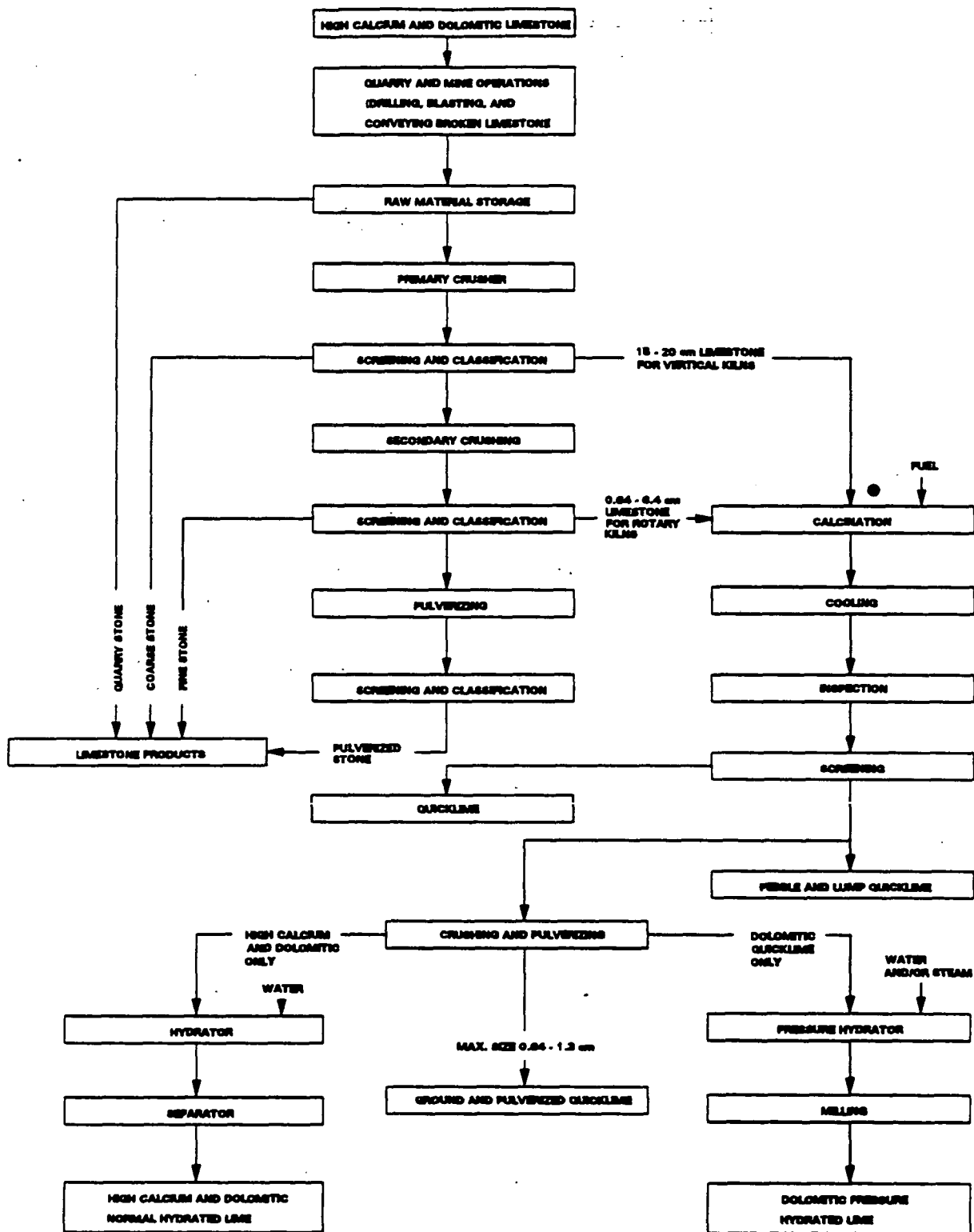


Figure 7-2. Process flow diagram for lime manufacturing process.⁷⁹

to be emitted in the lime kiln. Combustion of fuel in the lime kiln is the major contributor to mercury emissions.

7.2.2 Emission Control Measures

With the exception of the lime kiln, the emission sources in the lime manufacturing industry can be classified as either process emissions or fugitive emissions. The primary pollutants resulting from these fugitive sources are PM. No specific control measures for the lime industry are reported in the literature for the fugitive sources. The reduction measures used for fugitive dust sources at portland cement manufacturing facilities may also be applicable at lime manufacturing industries.

Air pollution control devices for lime kilns are primarily used to recover product or control fugitive dust and PM emissions. Calcination kiln exhaust is typically routed to a cyclone for product recovery, and then routed through a fabric filter or ESP's to collect fine particulate emissions. Other emission controls found at lime kilns include wet scrubbers (typically venturi scrubbers). How well these various air pollution control devices perform, relative to vapor phase mercury emissions in lime production, is not well documented. The control efficiencies are expected to be similar to those observed in the production of portland cement because of the similarities in the process and control devices.

7.2.3 Emissions

Mercury emissions from fuel combustion will occur from the lime kiln (calcination) as shown in Figure 7-2 by a solid circle. Mercury that may be present in the limestone can potentially also be emitted from the kiln. All other potential emission sources in the process are expected to be very minor contributors to overall mercury emissions. Emissions resulting from all five

processing steps include particulate matter. Additionally, emissions from the lime kiln include other products of fuel combustion such as SO_2 , NO_x , and CO .

Representative estimates of mercury emissions from lime manufacturing are not possible based on the available data from lime kilns in the U.S. An ongoing EPA study to update AP-42, Section 8.15, on lime manufacturing emission factors has reviewed and summarized test data for lime calcining at 93 kilns.⁷⁹ Pollutants identified and noted in a summary of the test data did not indicate any mercury emissions and gave little or no indication that emissions tests at lime kilns have sampled and analyzed for trace metals. However, one previous study provided 1983 mercury emission test data from five Wisconsin lime plants.

Emission estimates, based on mass balances generated from information for mercury content in limestone from the five operating lime kilns in Wisconsin in 1983, revealed mercury emission estimates of 18 kg/yr (39 lb/yr) for all the kilns combined.⁸⁰ In 1983, these five lime plants produced 0.29×10^6 Mg (0.32×10^6 tons) of lime.⁸¹ Assuming uniform emissions for each ton of production suggests that 5.5×10^{-2} g (1.2×10^{-4} lb) of mercury were emitted for each Mg (ton) of lime produced. These data do not account for any differences in fuel used to heat the kilns or any differences in raw materials used. However, because one-third of the lime kilns are fired with natural gas, which contains no mercury, estimated annual emissions should be reduced to reflect the differences in fuels (see Appendix A).

In the previous section, an emission factor for mercury emissions from the production of portland cement was estimated using the results of emission testing at 15 cement kilns. This estimated emission factor was 8.7×10^{-2} g (1.7×10^{-4} lb) of mercury emitted for each Mg (ton) of clinker produced. In the production of portland cement and in lime production, the major

source of any mercury emissions is from the kiln during the calcination process. In addition, the basic raw material (limestone) is the same for both products; the fuels are generally the same, although over one-third of the lime kilns use natural gas and oil may be used to a greater extent in portland cement production than in lime manufacture; and the emission controls are very similar, if not the same.

The mercury emission factor of 5.5×10^{-2} g/Mg of lime produced (1.2×10^{-4} lb/ton) based on the five lime kilns in Wisconsin has a high level of uncertainty. The material composition could vary significantly across the country, and the fuel type(s) used in Wisconsin may not be representative of those used nationwide. However, based on the overall similarity of the calcining process in lime manufacture with portland cement production and the similarities in the two emission factors, the emission factor based on the five Wisconsin kilns may be useful to provide an order of magnitude estimate of mercury emissions from lime manufacture.

7.3 CARBON BLACK PRODUCTION

Carbon black is produced by pyrolyzing petrochemical oil feedstock. A compilation of facilities, location, type of process, and annual capacity is presented in Table 7-2. A description of the process used to manufacture carbon black and the emissions resulting from the various operations is presented below.

7.3.1 Process Description⁸²

Carbon black is produced by partial combustion of hydrocarbons. The most predominantly used process (which accounts for more than 98 percent of carbon black produced) is based on a feedstock consisting of a highly aromatic petrochemical or carbo chemical heavy oil. Mercury can be

TABLE 7-2. CARBON BLACK PRODUCTION FACILITIES

Company	Location	Type of process ^a	Annual capacity ^b	
			10 ³ Mg	10 ⁶ lbs
Cabot Corporation North American Rubber Black Division	Franklin, Louisiana	F	141	310
	Pampa, Texas	F	32	70
	Villa Platte, Louisiana	F	127	280
	Waverly, West Virginia	F	82	180
Chevron Corporation Chevron Chemical Company, subsidiary Olefins and Derivatives Division	Cedar Bayou, Texas	A	9	20
Degussa Corporation	Aransas Pass, Texas	F	57	125
	Belpre, Ohio	F	59	130
	New Iberia, Louisiana	F	91	200
Ebonex Corporation	Melvindale, Michigan	C	4	8
General Carbon Company	Los Angeles, California	C	0.5	1
Hoover Color Corporation	Hiwassee, Virginia	C	0.5	1
J.M. Huber Corporation	Baytown, Texas	F	102	225
	Borger, Texas	F and T	79	175
	Orange, Texas	F	61	135
Phelps Dodge Corporation Colombian Chemical Company, subsidiary	El Dorado, Arkansas	F	50	110
	Moundville, West Virginia	F	77	170
	North Bend, Louisiana	F	109	240
	Ulysses, Kansas	F	36	80
Sir Richardson Carbon & Gasoline Company	Addis, Louisiana	F	66	145
	Big Spring, Texas	F	52	115
	Borger, Texas	F	98	215
Witco Corporation Continental Carbon Company, subsidiary	Phenix City, Alabama	F	27	60
	Ponca City, Oklahoma	F	66	145
	Sunray, Texas	F	45	100
	TOTAL		1,471	3,240

Source: Reference 16.

^aA = acetylene decomposition

C = combustion

F = furnace

T = thermal

^bCapacities are variable and based on SRI estimates as of January 1, 1991

expected to be present in the feedstock. Although the mercury content in the feedstock used to manufacture carbon black is not known, mercury content in petroleum crude is reported to range between 0.023 and 30 parts per million (ppm) by weight.⁸³ Figure 7-3 contains a flow diagram of this process.

Three primary raw materials used in this process are, preheated feedstock (either the petrochemical oil or carbochemical oil), which is preheated to a temperature between 150 and 250°C (302 and 482°F), preheated air, and an auxiliary fuel such as natural gas. A turbulent, high-temperature zone is created in the reactor by combusting the auxiliary fuel, and the preheated oil feedstock is introduced in this zone as an atomized spray. In this zone of the reactor, most of the oxygen would be used to burn the auxiliary fuel resulting in insufficient oxygen to combust the oil feedstock. Thus, pyrolysis (partial combustion) of the feedstock is achieved, and carbon black is produced. Most of the mercury present in the feedstock will be emitted in the hot exhaust gas from the reactor.

The product stream from the reactor is quenched with water, and any residual heat in the product stream is used to preheat the oil feedstock and combustion air before recovering the carbon in a fabric filter. Carbon recovered in the fabric filter is in a fluffy form. The fluffy carbon black may be ground in a grinder, if desired. Depending on the end use, carbon black may be shipped in a fluffy form or in the form of pellets. Pelletizing is done by a wet process in which carbon black is mixed with water along with a binder and fed into a pelletizer. The pellets are subsequently dried and bagged prior to shipping.

7.3.2 Emission Control Measures⁸²

High-performance fabric filters are reported to be used to control PM emissions from main process streams during the manufacture of carbon black. It is reported that the fabric

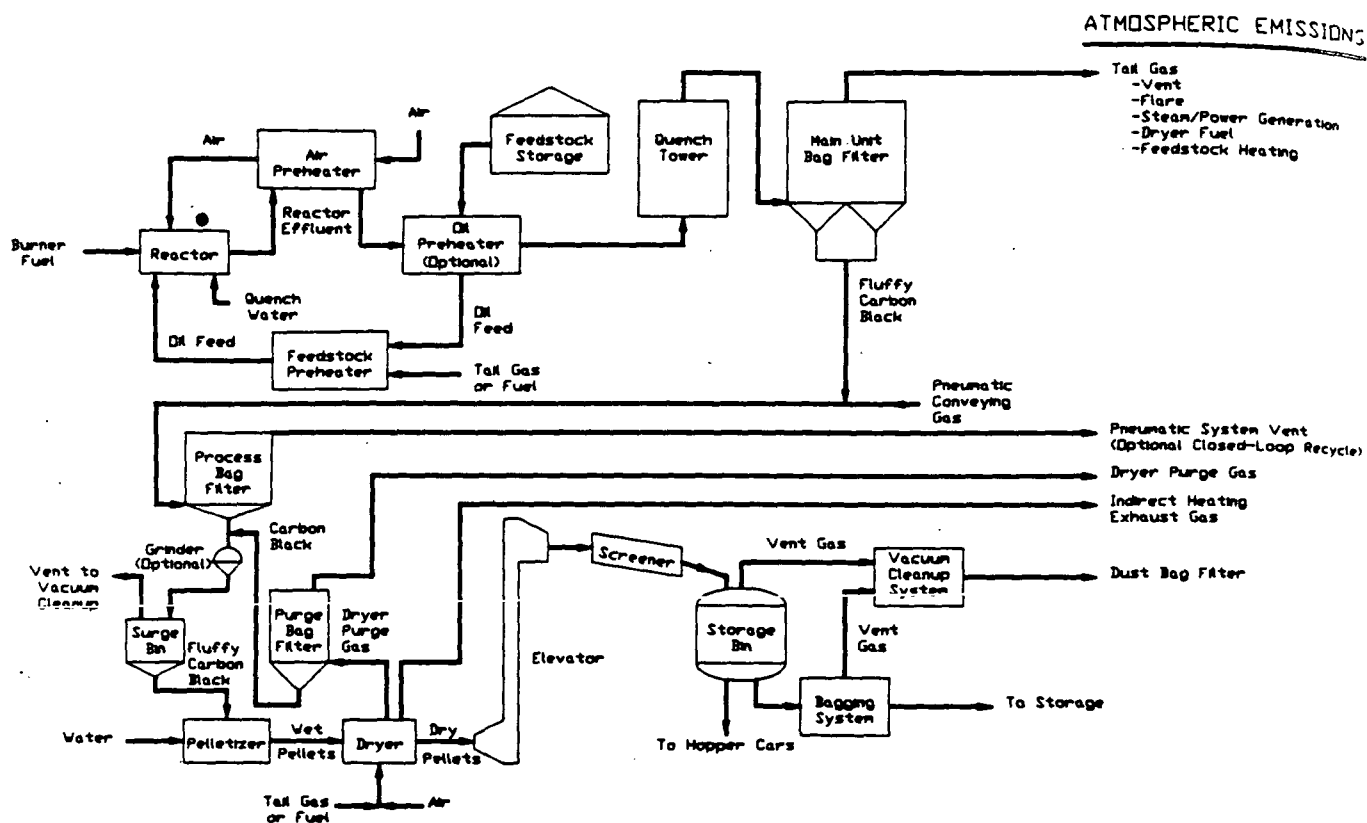


Figure 7-3. Process flow diagram for carbon black manufacturing process.⁸²

filters can reduce PM emissions to levels as low as 6 mg/m³ (normal m³). Mercury emissions from the reactor are primarily in the vapor phase and not as particulate. These emissions will proceed through the main process streams to the fabric filters. If the mercury remains in the vapor phase, the mercury control efficiency by the fabric filters is expected to be low. If the product gas stream is cooled to below 170°C (325°F), the fabric filter may capture a significant fraction of the condensed mercury, thus providing a high degree of emission control.

7.3.3 Emissions

The processing unit with the greatest potential to emit mercury is the reactor. Mercury emission sources are indicated in Figure 7-3 by solid circles. Mercury, which is present in the oil feedstock, can potentially be emitted during the pyrolysis step. However, no data are available on the performance of the fabric filter control systems for mercury emissions. The only available data are for emissions from the oil-furnace process. These data show mercury emission to be 0.15 g/Mg (3×10^{-4} lb/ton) from the main process vent.⁸⁴ The source of these data could not be obtained in order to verify the validity of the emission factors. Because the factors are not verified, they should be used with extreme caution.

7.4 BYPRODUCT COKE PRODUCTION

Byproduct coke, also referred to as metallurgical coke, is so named because it is produced as a byproduct when coal is distilled (in the absence of oxygen) to recover volatiles. These volatiles are refined to produce clean coke-oven gas, tar, sulfur, ammonium sulfate, and light oil. Table 7-3 contains a list of byproduct coke oven facilities reported to be in operation in 1991.⁸⁵ A description of the process used to manufacture byproduct coke and the emissions resulting from the various operations is presented below.

**TABLE 7-3. BYPRODUCT COKE PRODUCERS IN
THE UNITED STATES IN 1991**

Facility	Number of batteries	Total number of ovens	Total capacity, tons per day
Acme Steel, Chicago, IL	2	100	1,600
Armco, Inc., Ashland, KY	2	146	2,700
Armco, Inc., Middletown, OH	3	203	4,535
Bethlehem Steel, Bethlehem, PA	3	284	3,944
Bethlehem Steel, Burns Harbor, IN	2	164	4,380
Bethlehem Steel, Lackawanna, NY	2	152	1,872
Bethlehem Steel, Sparrows Point, MD	3	210	4,069
Geneva Steel, Orem, UT	1	208	2,250
Gulf States Steel, Gadsden, AL	2	130	2,800
Inland Steel, East Chicago, IN	6	446	5,775
LTV Steel, Pittsburgh, PA	5	315	5,404
LTV Steel, Chicago, IL	1	60	1,600
LTV Steel, Cleveland, OH	2	126	3,200
LTV Steel, Warren, OH	1	85	1,500
National Steel, Granite City, IL	2	90	1,520
National Steel, Ecorse, MI	1	78	925
USS, Div. of USX Corp., Clairton, PA	12	816	12,640
USS, Div. of USX Corp., Gary, IN	6	422	7,135
Wheeling-Pittsburgh Steel, East Steubenville, WV	4	224	3,800

Source: Reference 85.

7.4.1 Process Description^{73,86}

Coke is currently produced in two types of coke oven batteries: the slot oven byproduct battery and the nonrecovery battery. The slot oven byproduct type is the most commonly used battery. Over 99 percent of coke produced in 1990 was produced in this type of battery. The nonrecovery battery, as the name suggests, is one where the products of distillation are not recovered and are immediately combusted to provide energy within the plant. The nonrecovery battery is currently used at only one location; however, it is expected to be a more popular choice when existing plants are reconstructed. Figures 7-4 and 7-5 present the general layout and the emission points of a typical byproduct coke oven battery.

The byproduct coke oven battery consists of a series (ranging from 10 to 100) of narrow ovens, 400- to 600-mm- (16- to 24-inch) wide, and 12- to 18-meter (40- to 60-foot) long. The height of the ovens may range between 3 and 6 meters (10 and 20 feet). Depending on the dimensions, the production capacity may range between 7.5 and 39 tons of coke per batch. A heating flue is located between each oven pair.

Pulverized coal (which is the feedstock) is fed through ports located on the top, by a car (referred to as a larry car in the industry) that travels on tracks along the top of each battery. The ports are sealed upon charging, and gaseous fuel (usually cleaned coke oven gas) is combusted in the flues located between the ovens to provide the energy for the pyrolysis. The coking process takes place for between 12 and 20 hours, at the end of which almost all the volatile matter produced from the coal is driven off--thus forming coke. The coke is then unloaded from the ovens through vertical doors on each end of the oven into a rail car where it is quenched by spraying several thousand gallons of water. At the end of the coking cycle, the maximum temperature at the center of the coke mass could be as

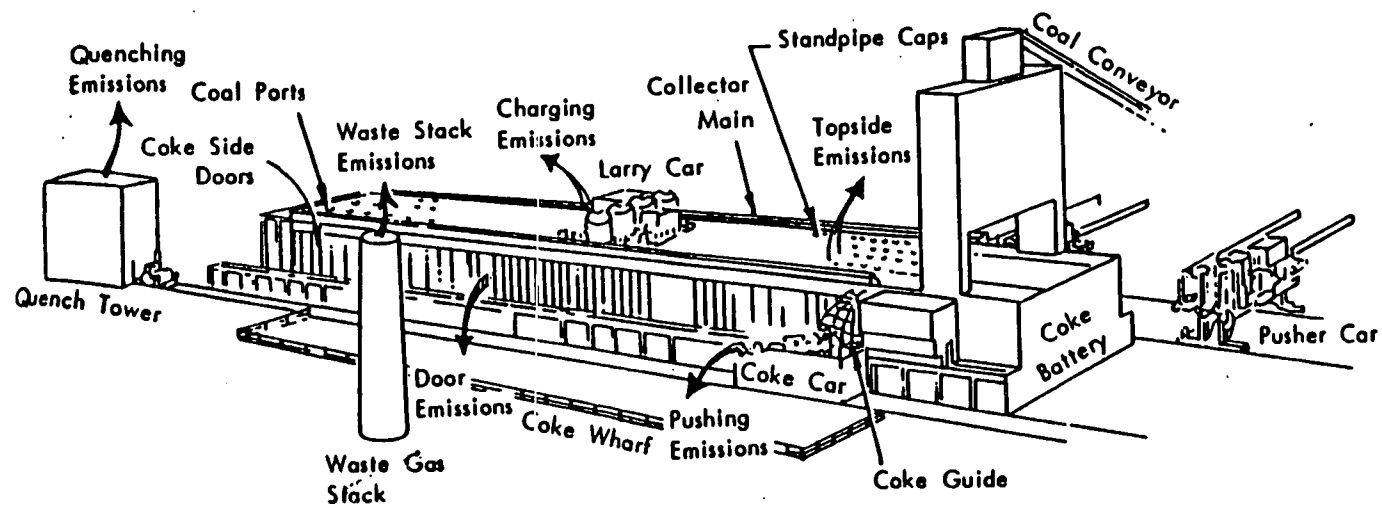


Figure 7-4. Schematic of byproduct coke oven battery.⁷³

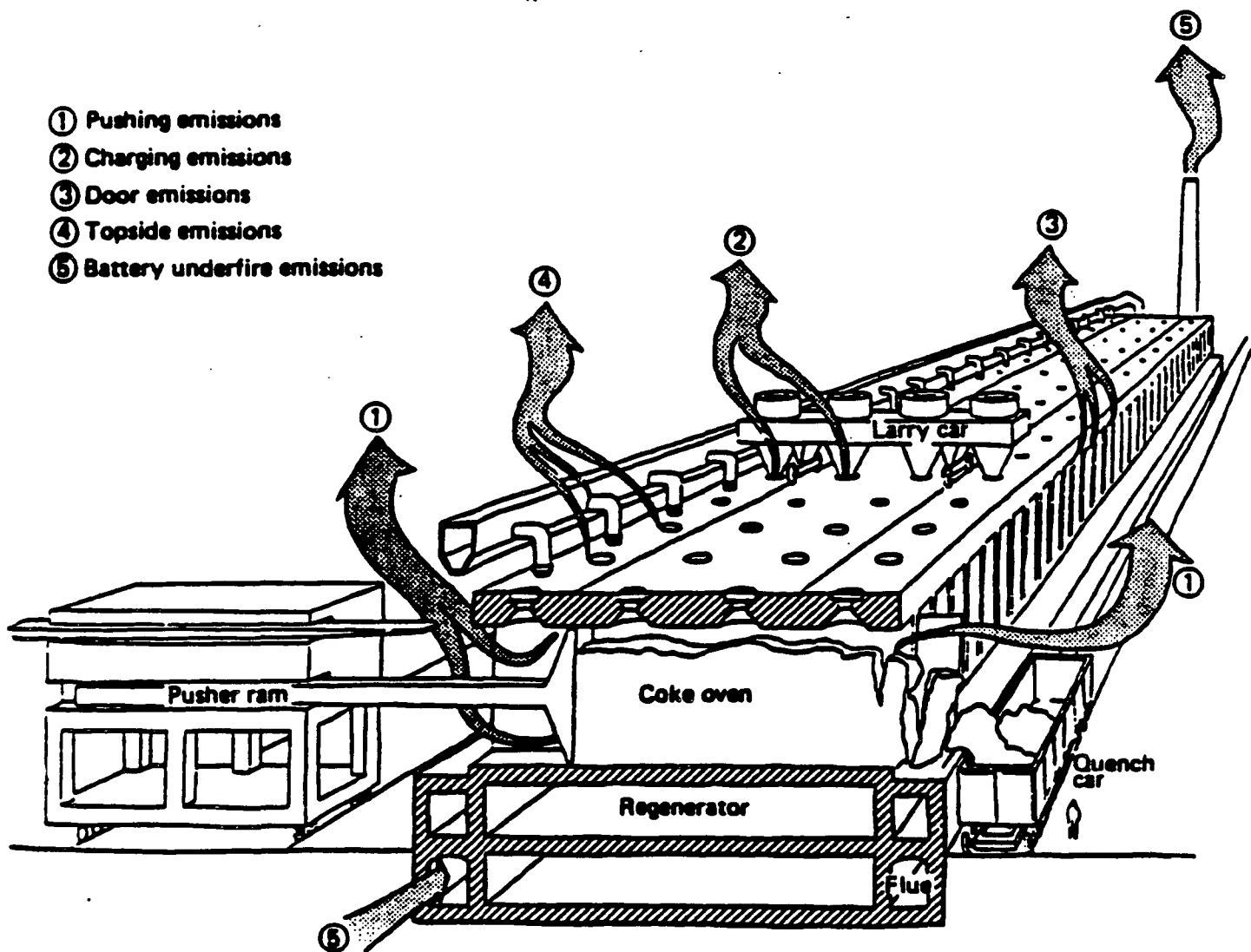


Figure 7-5. Types of air pollution emissions from coke oven batteries.⁷³

high as 1150°C (2100°F); therefore, the quenching is performed to cool down the coke and to prevent complete combustion of the coke upon exposure to air. The rail car then unloads the coke in a separate area where the coke is allowed to cool further.

Mercury is present in coal in appreciable quantities. Table 6-4 presented data pertaining to mercury levels in various types of U.S. coals. Depending on the type of coal used, the mercury content can be as high as 8 ppm by weight; however, values of about 1 ppm are more typical. The volatiles recovered from the coking operation will, therefore, contain mercury.

7.4.2 Emission Control Measures⁸⁶

The PM emissions resulting from coal preparation (pulverizing, screening, and blending) are controlled by cyclones. Oven charging produces PM and VOC emissions. The PM emissions are reduced by process modifications such as staged or sequential charging of coal into the coke oven.

Leaks of VOC through doors are reduced by door cleaning and maintenance, rebuilding of doors, and manual application of lute (seal) material. Charge lid and offtake leaks are reduced by an effective patching and luting program.

Pushing coke into the quench car produces PM, VOC, and other products of fuel combustion. Emission control devices used to control the emissions during quenching include ESP's, fabric filters, and wet scrubbers. These control devices are effective mainly for PM control. No data are available for the performance of these control systems for mercury emissions. However, because they typically operate at elevated temperatures [$>170^{\circ}\text{C}$ (325°F)] or greater, mercury removal is anticipated to be limited.

Fugitive PM generated from material handling operations such as, unloading, storing, and grinding of coal; screening,

crushing, storing, and loading of coke. Information pertaining to methods of control of fugitive emissions resulting from material handling operations is not available.

7.4.3 Emissions

Mercury, which is present in the coal, will be primarily emitted during the coking process. During the coking cycle, mercury emissions leak into the atmosphere through poorly sealed doors, charge lids, and offtake caps, and through cracks which may develop in oven brickwork, the offtakes, and collector mains. No documentation is available pertaining to mercury emissions resulting from the pyrolysis step. Emissions resulting from the various process steps during the manufacture of byproduct coke will also include PM, VOC, and CO.

7.5 PRIMARY LEAD SMELTING

Lead is recovered from a sulfide ore, primarily galena (lead sulfide--PbS), which also contains small amounts of copper, iron, zinc, and other trace elements such as mercury. A list of primary lead smelters currently in operation within the United States (U.S.) is given in Table 7-4.⁸⁷ A description of the process used to manufacture lead and the emissions resulting from the various operations are presented below.

TABLE 7-4. DOMESTIC PRIMARY LEAD SMELTERS AND REFINERIES

Smelter	Refinery	1990 Production, Mg (tons)
ASARCO, East Helena, MT	ASARCO, Omaha, NE	65,800 (72,500)
ASARCO, Glover, MO	Same site	112,000 (123,200)
Doe Run (formerly St. Joe), Herculaneum, MO	Same site	231,000 (254,100)

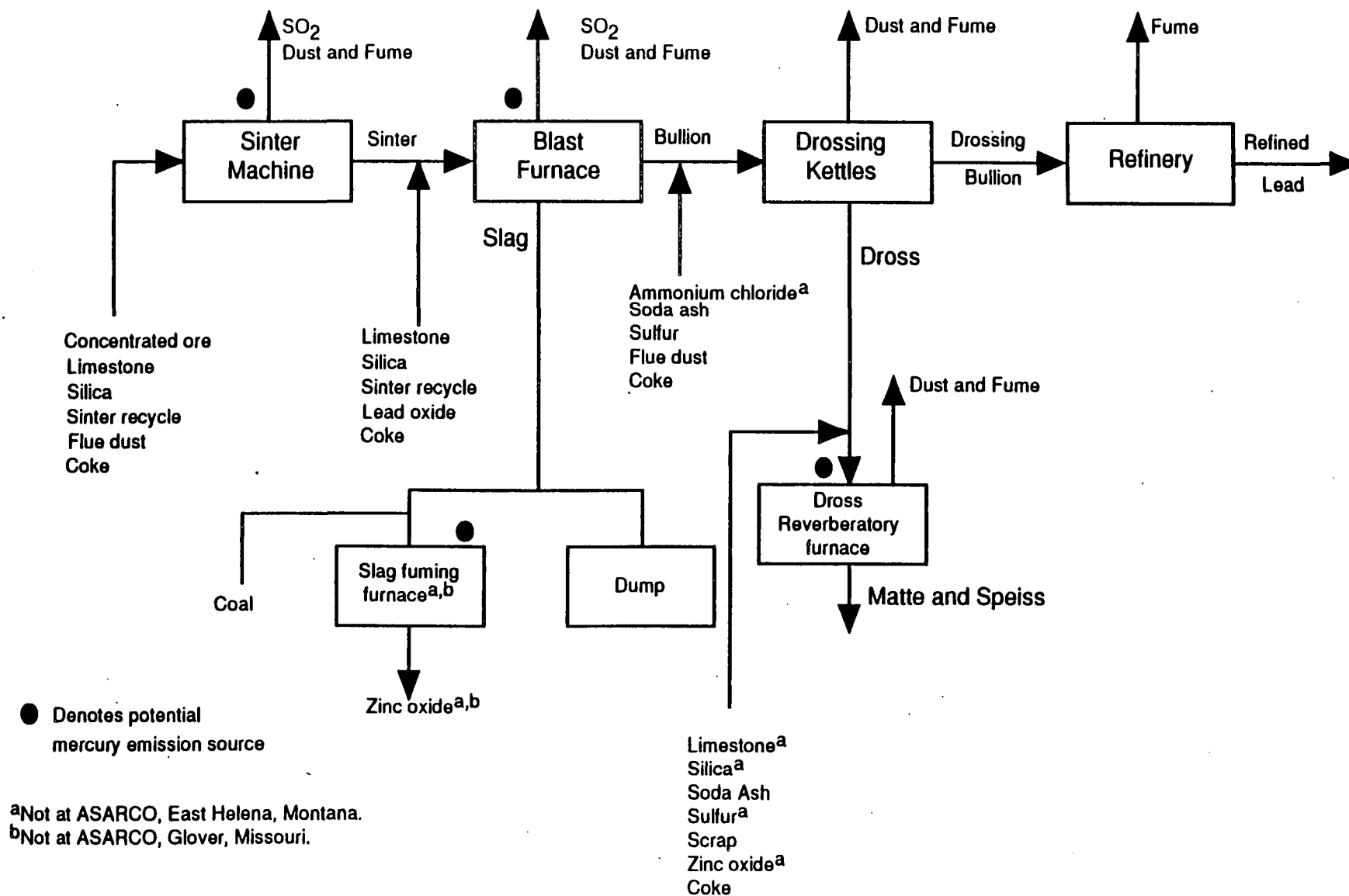
Source: Reference 87.

7.5.1 Process Description^{73,88}

Figure 7-6 contains a process flow diagram of primary lead smelting. The recovery of lead from the lead ore consists of three main steps: sintering, reduction, and refining.

Sintering is carried out in a sintering machine, which is a continuous steel pallet conveyor belt. Each pallet consists of perforated grates, beneath which are wind boxes connected to fans to provide a draft through the moving sinter charge. The sintering reactions take place at about 1000°C (1832°F) during which lead sulfide is converted to lead oxide. Since mercury and its compounds vaporize below this temperature, most of the mercury present in the ore can be expected to be emitted during sintering either as elemental mercury or as mercuric oxide.

Reduction of the sintered lead is carried out in a blast furnace at a temperature of 1600°C (2920°F). The furnace is charged with a mixture of sinter (80 to 90 percent of charge), metallurgical coke (8 to 14 percent of charge), and other materials, such as limestone, silica, litharge, and other constituents, which are balanced to form a fluid slag. In the blast furnace, the sinter is reduced to lead. The heat for the reaction is supplied by the combustion of coke. Slag, consisting of impurities, flows from the furnace and is either land deposited or is further processed to recover zinc. The impurities include arsenic, antimony, copper and other metal sulfides, iron, and silicates. Lead bullion, which is the primary product, undergoes a preliminary treatment to remove impurities, such as copper, sulfur, arsenic, antimony, and nickel. Residual mercury can be expected to be emitted during the reduction step. Further refining of the lead bullion is carried out in cast iron kettles. Refined lead, which is 99.99 to 99.999 percent pure, is cast into pigs for shipment.

Figure 7-6. Typical primary lead processing scheme.⁷³

7.5.2 Emission Control Measures⁷³

Emission controls on lead smelter operations are employed for controlling PM and SO₂ emissions resulting from the blast furnace and sintering machines. Centrifugal collectors (cyclones) may be used in conjunction with fabric filters or ESP's for PM control. The blast furnace and the sintering machine operate at very high temperatures (in excess of 1000°C [1832°F]), and as a result, mercury would be emitted from these sources in vapor form. Therefore, particulate control devices would have little effect on mercury emissions from the sintering machine and blast furnace. However, no collection efficiency data are available for mercury using these systems.

Control of SO₂ emissions is achieved by absorption to form sulfuric acid in the sulfuric acid plants, which are commonly part of lead smelting plants.

7.5.3 Emissions

Mercury, which may be present in the ore, may be emitted during the sintering and blast furnace steps and in the dressing area because these processes take place at high temperatures. Mercury emission sources are indicated on Figure 7-6 by solid circles.

The most recent emission factor data available for mercury emissions from primary lead smelting are presented in Table 7-5.⁸⁸ These data represent emission factors for a custom smelter operated by ASARCO in El Paso, Texas; this facility ceased operating in 1985. No recent mercury emission factors are available for the three current primary lead smelters. The custom smelter in El Paso obtained lead ore from several sources both within and outside the United States. These ores had a variable mercury content depending upon the source of the ore. Two of the three current smelters are not custom smelters; they

TABLE 7-5. MERCURY EMISSION FACTORS FOR PRIMARY LEAD SMELTING

Process	Emission factor		Notes
	g/Mg	lb/ton	
Materials Handling: Ore crushing	1.2 ^a	0.0024 ^a	Uncontrolled
Materials Handling: Sinter charge mixing	6.5 ^c	0.013 ^c	Uncontrolled
Sintering Machine leakage	0.7 ^b	0.0014	Uncontrolled
Blast furnace	1.9 ^c	0.0038 ^c	Baghouse sampling data
Slag fuming furnace	1.7 ^d	0.0034 ^d	Baghouse sampling data
Slag pouring	0.45 ^d	0.0009 ^d	Uncontrolled
Dross reverberatory furnace	0.08 ^c	0.00016 ^c	Uncontrolled sampling data

Source: Reference 88.

^aPer ton (or Mg) of raw materials.

^bPer ton (or Mg) of sinter.

^cPer ton (or Mg) of concentrated ore.

^dPer ton (or Mg) of lead product.

typically process ore from the vicinity of the smelter. The two smelters in Missouri use ore only from southeast Missouri; these ores have a very low mercury content. The ASARCO-East Helena plant, although a custom smelter, processes low mercury concentrates. None of the three primary lead smelters reported mercury emission data in the 1990 TRI, indicating that emissions from the sources are estimated to be below the TRI reporting threshold.

Because the data in Table 7-5 were based on ores with a variable mercury content and the current sources of lead ore have a low mercury content, the emission factors in Table 7-5 probably would lead to an overestimation of current emissions. Extreme caution should be exercised in the use of these emission factors to predict precise current emissions; however, the factors may provide an order of magnitude estimate. An alternative estimating method may be to use the actual mercury content of the ore and estimate emissions based on those data.

7.6 PRIMARY COPPER SMELTING

Copper is recovered from a sulfide ore principally by pyrometallurgical smelting methods. Copper ores contain small quantities of arsenic, cadmium, lead, antimony, and other heavy metals including mercury. Data pertaining to mercury content in the ore are not available.

A list of primary copper smelters currently in operation within the U.S. is given in Table 7-6.⁸⁹ A description of the process used to manufacture copper and the emissions resulting from the various operations is presented below.

TABLE 7-6. DOMESTIC PRIMARY COPPER SMELTERS AND REFINERIES

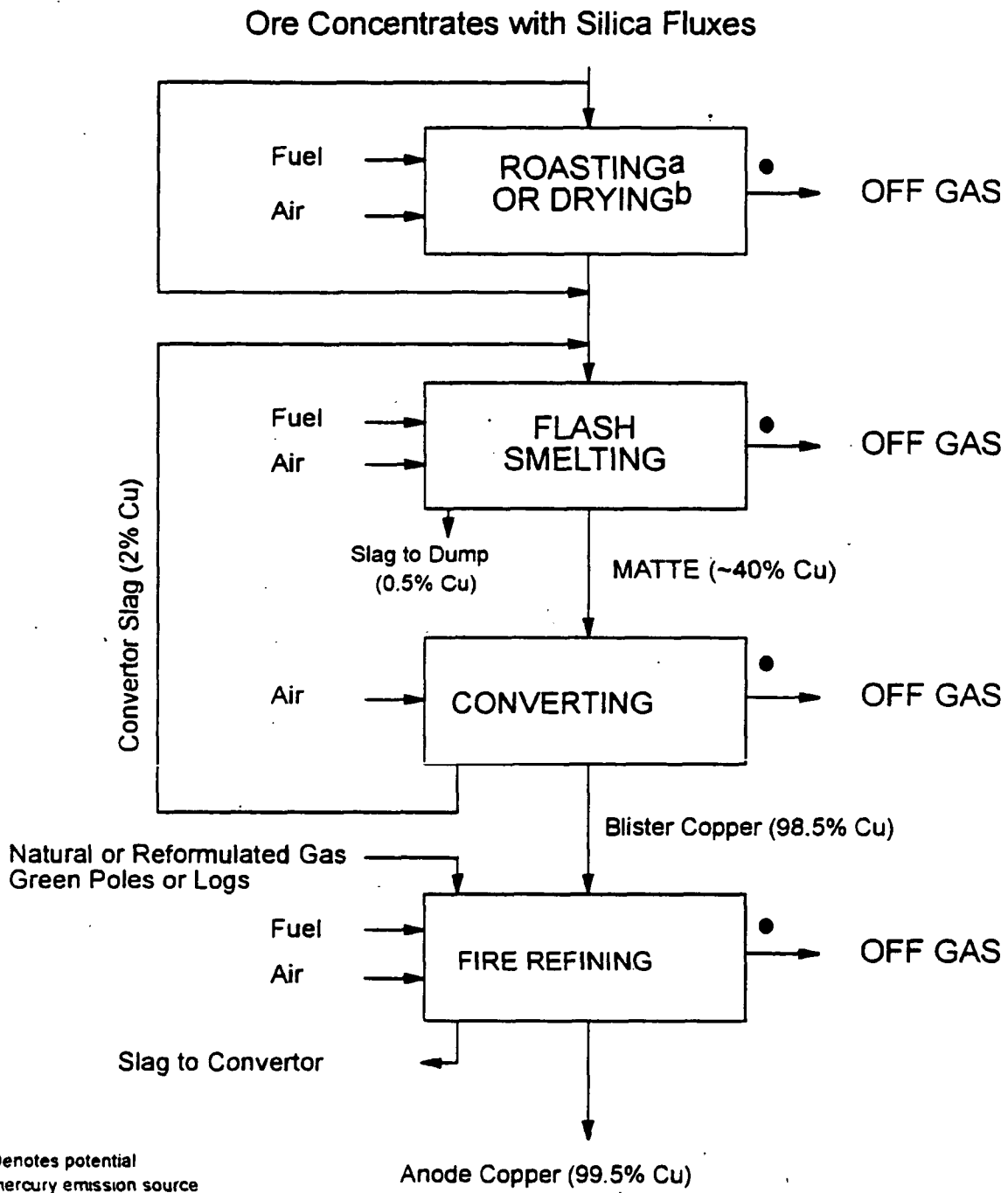
Smelter	1992 Capacity, Mg (tons)
ASARCO Inc., Hayden, AZ	191,000 (210,000)
Cyprus Miami Mining Co., Globe, AZ	180,000 (198,000)
MAGMA Copper Co., San Manuel, AZ	290,000 (319,000)
Copper Range Co., White Pine, MI	60,000 (66,000)
Phelps Dodge, Hidalgo, NM	190,000 (209,000)
Chino Mines Co., Hurley, NM	170,000 (187,000)
ASARCO Inc., El Paso, TX	100,000 (110,000)
Kennecott, Garfield, UT	210,000 (231,000)
ASARCO Inc., Amarillo, TX	Unknown
Phelps Dodge, El Paso, TX	Unknown

Source: Reference 89.

7.6.1 Process Description⁷³

The pyrometallurgical copper smelting process is illustrated in Figure 7-7. The traditionally used process includes roasting of ore concentrates to produce calcine, smelting of roasted (calcine feed) or unroasted (green feed) ore concentrates to produce matte, and converting of the matte to yield blister copper product (about 99 percent pure). Typically, the blister copper is fire refined in an anode furnace, cast into "anodes" and sent to an electrolytic refinery for further impurity elimination. The currently used copper smelters process ore concentrates by drying them in fluidized bed dryers and then converting and refining the dried product in the same manner as the traditionally used process.

In roasting, charge material of copper concentrate mixed with a siliceous flux (often a low grade ore) is heated in air to about 650°C (1200°F), eliminating 20 to 50 percent of the sulfur as SO₂. Portions of such impurities as antimony, arsenic, and lead are driven off, and some iron is converted to oxide. The



^aFirst step in the traditionally used copper-smelting process.

^bFirst step in the currently used copper-smelting process.

Figure 7-7. Typical primary copper smelter process.⁷³

roasted product, calcine, serves as a dried and heated charge for the smelting furnace. Either multiple hearth or fluidized bed roasters are used for roasting copper concentrate. Multiple hearth roasters accept moist concentrate, whereas fluid bed roasters are fed finely ground material (60 percent minus 200 mesh). With both of these types, the roasting is autogenous. Because there is less air dilution, higher SO_2 concentrations are present in fluidized bed roaster gases than in multiple hearth roaster gases. Because mercury has a boiling point of 350°C (660°F), most of the mercury in the ore may be emitted as an air pollutant during roasting.

In the smelting process, either hot calcines from the roaster or raw unroasted or dried concentrate is melted with siliceous flux in a flash smelting furnace to produce copper matte, a molten mixture of cuprous sulfide (Cu_2S), ferrous sulfide (FeS), and some heavy metals. The required heat comes from partial oxidation of the sulfide charge and from burning external fuel. Most of the iron and some of the impurities in the charge oxidize with the fluxes to form a slag atop the molten bath, which is periodically removed and discarded. Copper matte remains in the furnace until tapped. Mattes produced by the domestic industry range from 35 to 65 percent copper, with 45 percent the most common. The copper content percentage is referred to as the matte grade. Currently, five smelting furnace technologies are used in the U.S., reverberatory, electric, Noranda, Outokumpu (flash), and Inco (flash). Reverberatory furnace may operate at temperatures as high as 1500°C (2730°F). Flash furnaces may operate at temperatures as high as 1200° to 1300°C (2200° to 2300°F). Even though the exact temperatures at which the other two furnace technologies (electric and Noranda) operate are not known, it is probable that they operate at temperatures higher than the boiling point of mercury. Therefore, any residual mercury that remains in the calcine may be emitted as an air pollutant during the smelting step.

Reverberatory furnace operation is a continuous process, with frequent charging of input materials and periodic tapping of matte and skimming of slag. Heat is supplied by combustion of oil, gas or pulverized coal, and furnace temperature may exceed 1500°C (2730°F). Currently, a reverberatory furnace used at ASARCO, El Paso and an Isamelt furnace at Cyprus are being replaced with ConTop cyclone reactors (another type of flash smelting).

For smelting in electric arc furnaces, heat is generated by the flow of an electric current in carbon electrodes lowered through the furnace roof and submerged in the slag layer of the molten bath. The feed generally consists of dried concentrates or calcines, and charging wet concentrates is avoided. The chemical and physical changes occurring in the molten bath are similar to those occurring in the molten bath of a reverberatory furnace. Also, the matte and slag tapping practices are similar at both furnaces. Electric furnaces do not produce fuel combustion gases, so flow rates are lower and SO₂ concentrations higher in the effluent gas than in that of reverberatory furnaces.

Flash furnace smelting combines the operations of roasting and smelting to produce a high grade copper matte from concentrates and flux. In flash smelting, dried ore concentrates and finely ground fluxes are injected, together with oxygen, preheated air, or a mixture of both, into a furnace of special design, where temperature is maintained at approximately 1200 to 1300°C (2200 to 2300°F). Most flash furnaces, in contrast to reverberatory and electric furnaces, use the heat generated from partial oxidation of their sulfide charge to provide much or all of the energy (heat) required for smelting. They also produce offgas streams containing high concentrations of SO₂. Other flash furnaces, such as ConTop cyclone reactors, use oxyfuel combustion to generate the heat required for oxidation.

Slag produced by flash furnace operations typically contains higher amounts of copper than does that from reverberatory or electric furnace operations. As a result, the flash furnace and converter slags are treated in a slag cleaning furnace to recover the copper (not conducted at the ASARCO, Hayden facility). Slag cleaning furnaces usually are small electric furnaces. The flash furnace and converter slags are charged to a slag cleaning furnace and are allowed to settle under reducing conditions, with the addition of coke or iron sulfide. The copper, which is in oxide form in the slag, is converted to copper sulfide, is subsequently removed from the furnace and is charged to a converter with regular matte. If the slag's copper content is low, the slag is discarded.

The Noranda process, as originally designed, allowed the continuous production of blister copper in a single vessel by effectively combining roasting, smelting, and converting into one operation. Metallurgical problems, however, led to the operation of these reactors for the production of copper matte. As in flash smelting, the Noranda process takes advantage of the heat energy available from the copper ore. The remaining thermal energy required is supplied by oil burners, or by coal mixed with the ore concentrates.

The final step in the production of blister copper is converting, with the purposes of eliminating the remaining iron and sulfur present in the matte and leaving molten "blister" copper. All but one U. S. smelter uses Pierce-Smith converters, which are refractory lined cylindrical steel shells mounted on trunnions at either end, and rotated about the major axis for charging and pouring. An opening in the center of the converter functions as a mouth through which molten matte, siliceous flux, and scrap copper are charged and gaseous products are vented. Air or oxygen-rich air is blown through the molten matte. Iron sulfide (FeS) is oxidized to iron oxide (FeO) and SO_2 , and the FeO blowing and slag skimming are repeated until an adequate

amount of relatively pure Cu_2S , called "white metal", accumulates in the bottom of the converter. A renewed air blast oxidizes the copper sulfide to SO_2 , leaving blister copper in the converter. The blister copper is subsequently removed and transferred to refining facilities. This segment of converter operation is termed the finish blow. The SO_2 produced throughout the operation is vented to pollution control devices.

One domestic smelter uses Hoboken converters. The Hoboken converter is essentially like a conventional Pierce-Smith converter, except that this vessel is fitted with a side flue at one end shaped as an inverted U. This flue arrangement permits siphoning of gases from the interior of the converter directly to the offgas collection system, leaving the converter mouth under a slight vacuum. The Hoboken converters are also equipped with secondary hoods to further control emissions.

Blister copper usually contains from 98.5 to 99.5 percent pure copper. Impurities may include gold, silver, antimony, arsenic, bismuth, iron, lead, nickel, selenium, sulfur, tellurium, and zinc. To purify blister copper further, fire refining and electrolytic refining are used. In fire refining, blister copper is placed in an anode furnace, a flux is usually added, and air is blown through the molten mixture to oxidize remaining impurities, which are removed as a slag. The remaining metal bath is subjected to a reducing atmosphere to reconvert cuprous oxide to copper. Temperature in the furnace is around 1100°C (2010°F). The fire-refined copper is cast into anodes. Further refining separates the copper from impurities by electrolysis in a solution containing copper sulfate and sulfuric acid. Metallic impurities precipitate from the solution and form a sludge that is removed and treated to recover precious metals. Copper is dissolved from the anode and deposited at the cathode. Cathode copper is remelted and cast into bars, rods, ingots, or slabs for marketing purposes. The copper produced is 99.95 to

99.97 percent pure. Any mercury emission during the refining step will only be minimal.

7.6.2 Emission Control Measures⁷³

Emission controls on copper smelters are employed for controlling PM and SO₂ emissions resulting from roasters, smelting furnaces, and converters. Electrostatic precipitators are the common PM control devices employed at copper smelting facilities.

Control of SO₂ emissions is achieved by absorption to sulfuric acid in the sulfuric acid plants, which are commonly part of copper smelting plants.

7.6.3 Emissions

The main source of mercury will be during the roasting step and in the smelting furnace. Converters and refining furnaces may emit any residual mercury left in the calcine. These sources are denoted by solid circles in Figure 7-7. Data pertaining to mercury emissions from copper primary copper smelting facilities are limited. One emission test report at Copper Range Company located in White Pine, MI, containing results of metals analysis was reviewed during this study.⁹⁰ This facility operates a reverberatory furnace which is controlled by an ESP. The exhaust stream from the converter (which is uncontrolled) is mixed with the exhaust from the ESP outlet and is routed through the main stack and discharged into the atmosphere. Testing for metals was done at the main stack after the two exhaust streams (from the ESP outlet and the converter) are mixed. Mercury emissions were measured for three modes of converter operation, slag-blow, copper-blow and converter idle (no blow) cycles. Mercury level during the converter idle cycle was measured to be the highest, corresponding to a mercury emission rate of 0.1661 lb/hr. Additionally, the plant capacity was reported to be approximately

42 tons/hr of feed which consists of mill concentrate, limestone, iron pyrites, and recycled material. The actual process rate during the test is not known. Since the feed mix varies from facility to facility, the mercury emissions measured at Copper Range Company, cannot be used to estimate a general mercury emission factor that would be valid industrywide. Additionally, Copper Range Company, is the only facility in the U. S. which operates a reverberatory furnace. All other copper smelting furnaces use flash furnaces which inherently produce less emissions.

7.7 PETROLEUM REFINING

Petroleum refining involves the conversion of crude petroleum oil into refined products, including liquified petroleum gas, gasoline, kerosene, aviation fuel, diesel fuel, fuel oils, lubricating oils, and feedstocks for the petroleum industry.

As of January 1992, there were 32 oil companies in the United States with operable atmospheric crude oil distillation capacities in excess of 100,000 barrels per calendar day. These oil companies operated refiners at a total of 110 different locations. In addition, there were 72 companies with distillation capacities of less than 100,000 barrels per calendar day. A listing of all companies, specific refinery locations, and distillation capacities is presented in Appendix D.⁹¹

Mercury is reported to be present in petroleum crude, and its content in petroleum crude is reported to range between 0.023 and 30 parts per million (ppm) by weight.⁸³ A description of the processes used in petroleum refining and emissions resulting from the various operations is presented below.

7.7.1 Process Description^{73,92,93}

Figure 7-8 presents a schematic of an integrated petroleum refinery. The processes and operations shown in Figure 7-8 show a general processing arrangement. However, it may vary among refineries depending upon the specific products produced. The operations at petroleum refineries are classified into five general categories, as listed below:

1. Separation processes,
2. Petroleum conversion processes,
3. Petroleum treating processes,
4. Feedstock and product handling, and
5. Auxiliary facilities.

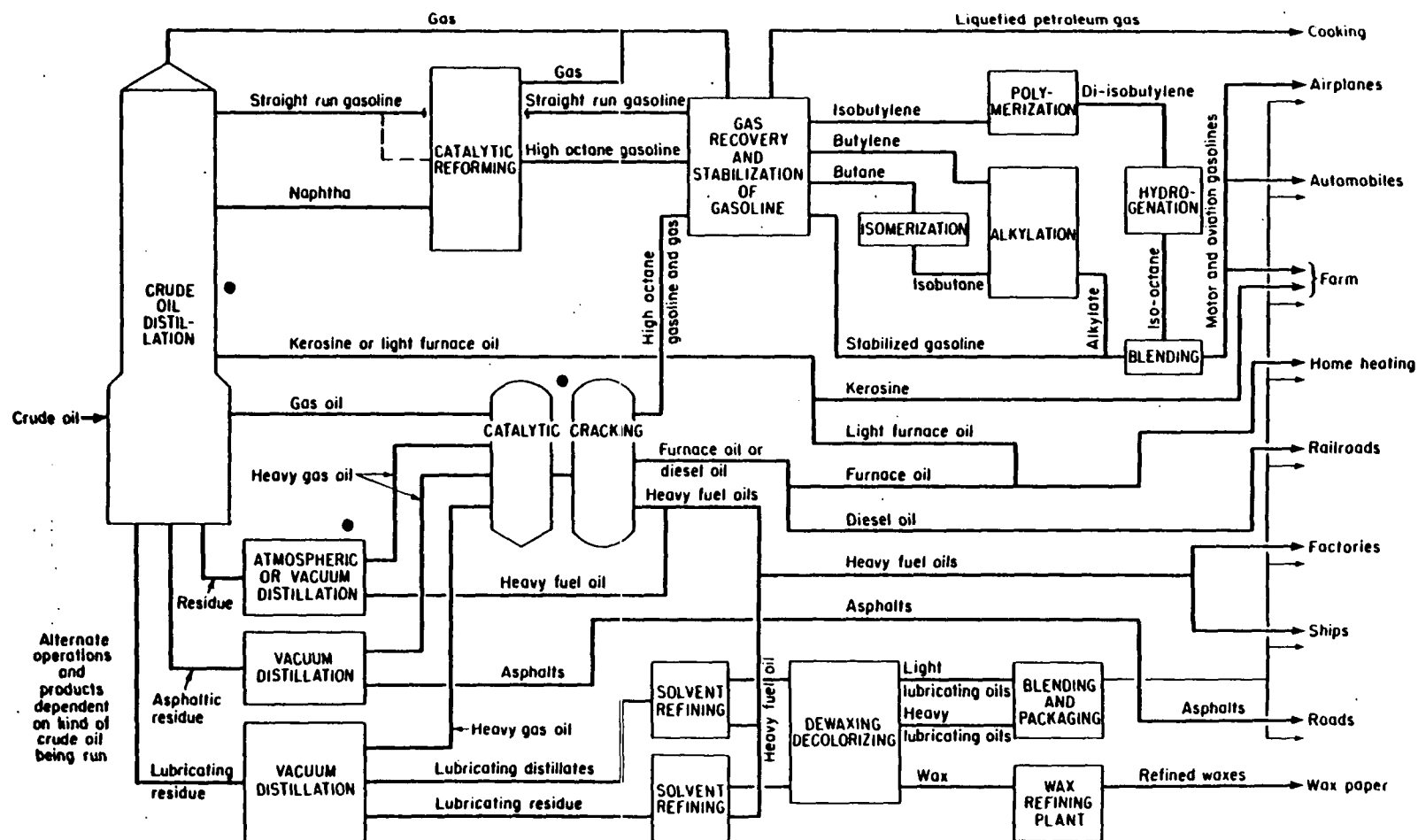
Separation processes--

Constituents of crude oil include paraffinic, naphthenic, and aromatic hydrocarbon compounds. Impurities may include sulfur, nitrogen, and metals. Three separation processes used to separate these constituents include: atmospheric distillation, vacuum distillation, and recovery of light ends (gas processing).

Atmospheric distillation results in the formation of bottoms consisting of high-boiling-point hydrocarbons. Topped crude withdrawn from the bottoms of atmospheric distillation can be separated further by vacuum distillation.

In vacuum distillation, the topped crude is heated in a process heater to temperatures ranging from 370° to 425°C (700° to 800°F) and subsequently flashed in a multi-tray vacuum distillation column, operating at vacuums ranging from 350 to 1,400 kg/m² (0.5 to 2.0 psia). Standard petroleum fractions withdrawn from the vacuum distillation include lube distillates, vacuum oil, asphalt stocks, and residual oils.

Distillation is carried out at temperatures higher than the boiling point of mercury. Therefore, the distillation step can be expected to be the primary source of mercury emissions.

Figure 7-8. Schematic of an example integrated petroleum refinery.⁹³

Conversion processes--

Conversion processes include cracking, coking, and visbreaking, which break large molecules into smaller molecules; isomerization and reforming processes to rearrange the structures of molecules; and polymerization and alkylation to combine small molecules into larger ones. Residual mercury from the separation processes is probably emitted during the conversion processes.

Catalytic cracking--using heat, pressure, and catalysts--converts heavy oils into lighter products. Feedstocks are usually gas oils from atmospheric distillation, vacuum distillation, coking, and deasphalting processes, and they have a boiling range of 340° to 540°C (650° to 1000°F). Two types of cracking units, the fluidized catalytic cracking (FCC) unit and the moving-bed catalytic cracking unit, are used in the refineries. Figure 7-9 presents a schematic of a fluid catalytic cracking unit.⁹²

Visbreaking is a thermal cracking process used to reduce the viscosity of the topped crude or vacuum distillation residues. The feedstock is heated and thermally cracked at a temperature ranging between 455° and 480°C (850° and 900°F) and pressure ranging between 3.5 and 17.6 kg/cm² (50 and 250 psia). The cracked products are quenched with gas oil and flashed into a fractionator. The vapor overhead from the fractionator is separated into light distillate products. A heavy distillate is recovered from the fractionator liquid.

Coking is also a thermal cracking process used to convert low value residual fuel oil to higher value gas oil and petroleum coke. This process is carried out at high temperature and low pressure, and the resulting products include petroleum coke, gas oils, and lighter petroleum stocks.

Equipment commonly used during conversion includes process heaters and reformers. Process heaters are used to raise the

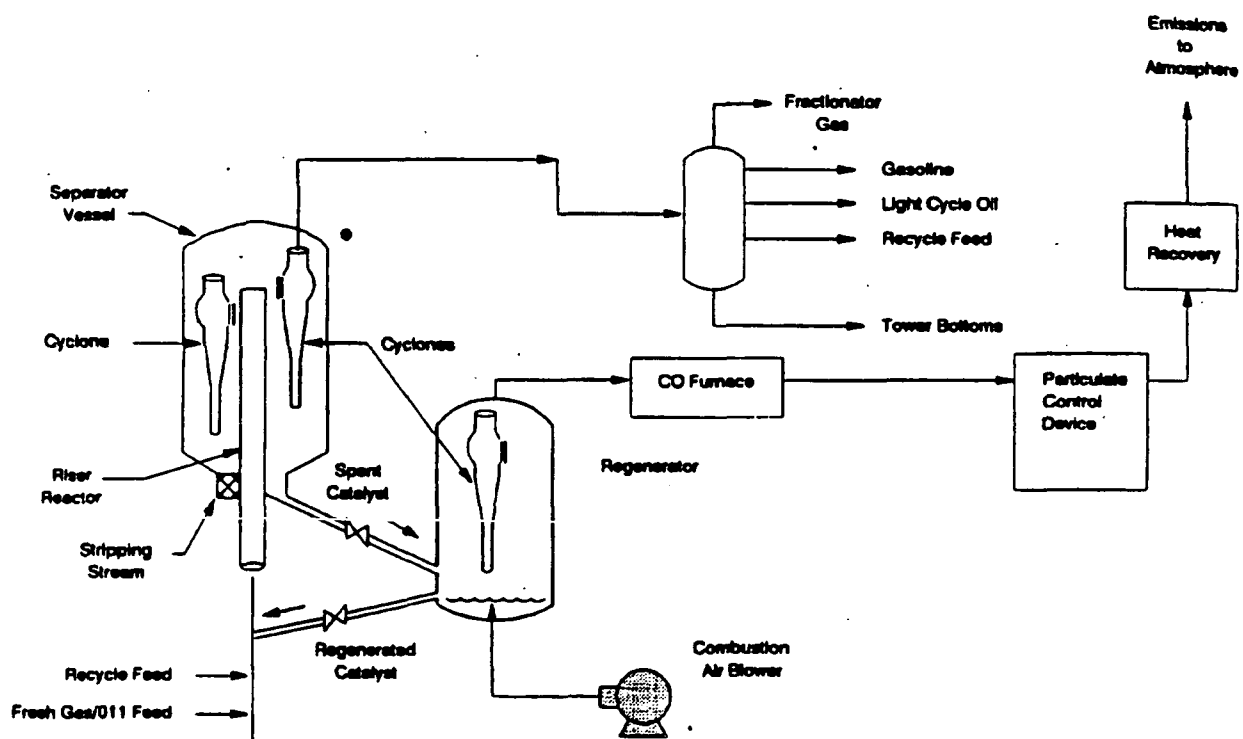


Figure 7-9. Schematic of fluidized bed catalytic cracking unit.⁹²

temperature of petroleum feedstocks to a maximum of 510°C (950°F). Fuels burned include refinery gas, natural gas, residual fuel oils, or combinations. Reformers are reactors where the heat for the reaction is supplied by burning fuel. For example, the reforming of natural gas by steam takes place in a reformer equipped with tubes. The natural gas and steam are introduced through the tubes, and the energy for the reaction is supplied by burning fuel in burners located outside the tubes.

The conversion steps, cracking, coking, and visbreaking, described above can be expected to be the secondary sources of mercury emissions.

Treatment processes--

Petroleum treatment processes include hydrodesulfurization, hydrotreating, chemical sweetening, acid gas removal, and deasphalting. These treatment methods are used to stabilize and upgrade petroleum products. Removal of undesirable elements, such as sulfur, nitrogen, and oxygen, is accomplished by hydrodesulfurization, hydrotreating, chemical sweetening, and acid gas removal. Deasphalting is carried out to separate asphaltic and resinous materials from petroleum products. Hydrotreating is a process in which the oil feed is treated by mixing with hydrogen in a fixed-bed catalyst reactor. Removal of acid gas involves controlling emissions of SO₂. Elemental sulfur is recovered as a byproduct.

Asphalt blowing is carried out by blowing air through the vacuum distillation residue to polymerize asphalt by oxidation. Feed is preheated to a temperature ranging between 200° and 320°C (400° and 600°F) prior to blowing air. The off gases (asphalt fumes) are commonly treated (for VOC control) in an incinerator prior to being released into the atmosphere.

Distillate sweetening is a catalytic process carried out in a fixed-bed catalytic reactor in which sulfur is introduced in

the sour distillate along with small quantities of caustic and air.

Any residual mercury left over in the feedstock after the separation and conversion steps can be expected to be emitted during the treatment step.

Feedstock and product handling--

This includes storage, blending, loading, and unloading of petroleum crude and products. No mercury emissions are expected during these steps.

Auxiliary facilities--

Auxiliary facilities include boilers, gas turbines, wastewater treatment facilities, hydrogen plants, cooling towers, and sulfur recovery units. Boilers and gas turbines cogeneration units within petroleum refineries may burn refinery gas.

7.7.2 Emission Control Measures

Control of VOC (and in some instances, CO) emissions from distillation, catalytic cracking, coking, blowdown system, sweetening, and asphalt blowing is achieved by flares. In some instances, the VOC-laden gas stream is also used as fuel in process heaters.

Control of PM emissions from catalytic cracking is achieved by using cyclones in conjunction with ESP's.

7.7.3 Emissions

Emissions of mercury can be expected during the process steps where petroleum crude is processed at high temperatures, such as the distillation, cracking, visbreaking, and other conversion steps. Potential mercury emission sources are identified in Figures 7-8 and 7-9 by solid circles. Other

emissions from petroleum refining operations include mainly PM, VOC, and products of fuel combustion. An emission factor for uncontrolled emissions from the fluid coking unit in the conversion step was cited in SPECIATE to be 3×10^{-5} g/liter (0.0105 lb/ 1,000 barrels) of fresh feed.⁹⁴ The source of these data could not be obtained in order to verify the validity of the emission factors. Because the factors are not verified, they should be used with extreme caution. The only additional data available pertaining to mercury emissions are those documented for process heaters and reformers. Based on a series of emission tests carried out in California, emission estimates for mercury are available for refinery gas-fired process heaters, boilers, gas turbine cogeneration units, and asphalt fume incinerators.⁹⁵ Table 7-7 contains emission factors for mercury from the above mentioned sources.

TABLE 7-7. MERCURY EMISSION FACTORS FOR MISCELLANEOUS SOURCES AT PETROLEUM REFINING FACILITIES.

Process Unit	Mercury emission factor	
	kg/10 ¹⁵ J	lb/10 ¹² Btu
Process heater (refinery gas-fired)	0.09	0.2
Boiler (refinery gas-fired)	6.0	14
Gas-fired cogeneration unit (refinery gas-fired)	2.8	6.6
Asphalt fume incinerator (this is an emission control device to treat the fumes resulting from asphalt blowing operation)		
- Blow cycle	3.4	8
- No blow cycle	3.7	8.5

Source: Reference 95.

The emission factors in Table 7-7 were derived based on an emission test. Details pertaining to the process conditions during the test are not known. Additionally, the emission factor for the asphalt fume incinerator is based on measurements taken at the outlet of the fume incinerator, which is an emission control device for the asphalt blowing process. Details

pertaining to any auxiliary fuel used in the fume incinerator are not known. Therefore, it is not possible to estimate how much of the mercury measured is contributed by the fuel used in the fume incinerator as opposed to that created by the asphalt blowing process. Additionally, since the asphalt fume incinerator is employed primarily for VOC control, the emission factors for mercury given in Table 7-7 represent uncontrolled emission factors.

7.8 OIL SHALE RETORTING

Oil shale is a marlstone-type sedimentary inorganic material containing complex organic polymers. These complex organic polymers are high-molecular-weight solids. Mercury may be expected to be present in oil shale. However, no data are available pertaining to mercury content in oil shale. The composition of inorganic and organic constituents of oil shale is completely dependent on deposit location.⁹⁶

Thermal decomposition of oil shale is referred to as oil shale retorting. A description of the processes used in oil shale retorting and emissions resulting from the various operations is presented below.

7.8.1 Process Description^{96,97}

The retorting process breaks down the high molecular weight complex organic polymers contained in oil shale (referred to as kerogen) into liquid, gaseous, and solid products. The oil shale pyrolysis process is carried out approximately at a temperature of 480°C (900°F). Pyrolysis reduces the kerogen into coke, gas, and liquid. Additional details pertaining to the composition of the oil and gaseous products are not available.

Processing of oil shale involves four steps: feed preparation, retorting, product recovery, and waste disposal.

There are three general classes of oil shale feed preparation and retort technology: (1) mining, followed by surface retorting, (2) true in situ (TIS), and (3) modified in situ (MIS). In surface retorting, oil shale is mined by conventional underground or open pit methods, and the oil is recovered in an above-ground retort. With TIS technology, the retorting takes place underground in the oil shale deposit. Modified in situ technology is a cross between surface and TIS technologies where the initial 15 to 40 percent of the oil shale is mined and retorted in a surface facility, and the remaining 60 to 85 percent of the shale is retorted in-place underground.

The retorting step may be expected to be the primary source of mercury emissions.

7.8.2 Emission Control Measures

Flares are reported to be used to control VOC emissions resulting from the retorting process. No other details are available pertaining to air pollution devices used in oil shale processing operations.

7.8.3 Emissions

At this time, there are no commercial oil shale retorting operations being conducted in the United States.

7.9 GEOTHERMAL POWER PLANTS⁹⁸

Geothermal power plants are either dry-steam or water-dominated and emitted an estimated 1.3 Mg (1.4 tons) of mercury in 1992. For dry-steam plants, steam is pumped from geothermal reservoirs to turbines at a temperature of about 180°C (360°F) and a pressure of 7.9 bars absolute. For water-dominated plants, water exists in the producing strata at a temperature of approximately 270°C (520°F) and at a pressure slightly higher

than hydrostatic. As the water flows towards the surface, pressure decreases and steam is formed, which is used to operate the turbines. There are currently 18 geothermal power plants operating in the United States.⁹⁹ Table 7-8 lists the names, locations, and capacities of these facilities.

Mercury can be expected to be present in the steam and water because it is recovered from beneath the earth's surface. However, no data on the mercury content of steam or water cycled through geothermal facilities are available.

7.9.1 Emission Control Measures

No information is available pertaining to air pollution control systems used in geothermal power plants.

7.9.2 Emissions

Mercury emissions at geothermal power plants are documented to result from two sources: off-gas ejectors, and cooling towers. Table 7-9 contains the mercury emission factors for these two sources. These data are based on measurements taken in 1977.⁹⁸ No process data are given in the documentation containing the test results and the primary source of these data could not be obtained in order to verify the validity of the emission factors. If significant process modifications or changes in control strategies have been incorporated since 1977, the emission factors reported in Table 7-9 may no longer be valid.

**TABLE 7-8. CURRENT OPERATING GEOTHERMAL POWER PLANTS
IN THE UNITED STATES IN 1992**

Facility	Type	Net capacity (MW)
The Geysers, CA	Dry-steam	1,805.7
Salton Sea, CA	Water-dominated	218.3
Heber, CA	Water-dominated	47.0
East Mesa, CA	Water-dominated	106.0
Coso, CA	Water-dominated	247.5
Casa Diablo, CA	Water-dominated	34.0
Amedee, CA	Water-dominated	2.0
Wendel, CA	Water-dominated	0.7
Dixie Valley, NV	Water-dominated	57.0
Steamboat Hot Springs, NV	Water-dominated	19.3
Beowawe Hot Springs, NV	Water-dominated	16.7
Desert Peak, NV	Water-dominated	9.0
Wabuska Hot Springs, NV	Water-dominated	1.7
Soda Lake, NV	Water-dominated	15.7
Stillwater, NV	Water-dominated	12.5
Empire and San Emidio, NV	Water-dominated	3.2
Roosevelt Hot Springs, UT	Water-dominated	20.0
Cove Fort, UT	Water-dominated	12.1
Total		2,628.4

Source: Reference 99.

**TABLE 7-9. MERCURY EMISSION FACTORS FOR GEOTHERMAL
POWER PLANTS**

Source	Emission factor range, g/Mwe/hr	Average emission factor	
		g/Mwe/hr	lb/Mwe/hr
Off-gas ejectors	0.00075 - 0.02	0.00725	0.00002
Cooling tower exhaust	0.026 - 0.072	0.05	0.0001

Source: Reference 98.

SECTION 8

EMISSIONS FROM MISCELLANEOUS FUGITIVE AND AREA SOURCES

8.1 MERCURY CATALYSTS

Mercury catalysts are used in the production of polyurethane and vinyl chloride. According to 1991 data, U.S. consumption of refined mercury for "other chemical and allied products" includes catalysts for plastics and miscellaneous catalysts. This entire category was reported to have consumed 18 Mg (20 tons) of mercury metal in 1991, which represents about four percent of the total mercury consumed in the U.S.¹⁰⁰

8.1.1 Process Description

Catalysts involved in the production of polyurethane have been composed of the phenylmercuric compounds ($C_6H_5Hg^+$), but few facilities currently use this catalyst. The location of these facilities is unknown.

Two processes can be used to manufacture vinyl chloride: one process based on acetylene uses mercuric chloride on carbon pellets as a catalyst, and the other is based on the oxychlorination of ethylene. Vinyl chloride is always produced by oxychlorination except at Borden Chemical and Plastics Corporation. Borden Chemical and Plastics produces about 136,000 Mg (149,600 tons) of vinyl chloride using mercuric chloride as a catalyst with acetylene. This represents approximately 2.5 percent of the total U.S. production.¹⁶ Figure 8-1 shows a flow diagram for this manufacturing process. To produce 136,000 Mg (149,600 tons) of vinyl chloride requires 57,500 Mg (63,000 tons) acetylene, 79,000 Mg (87,000 tons)

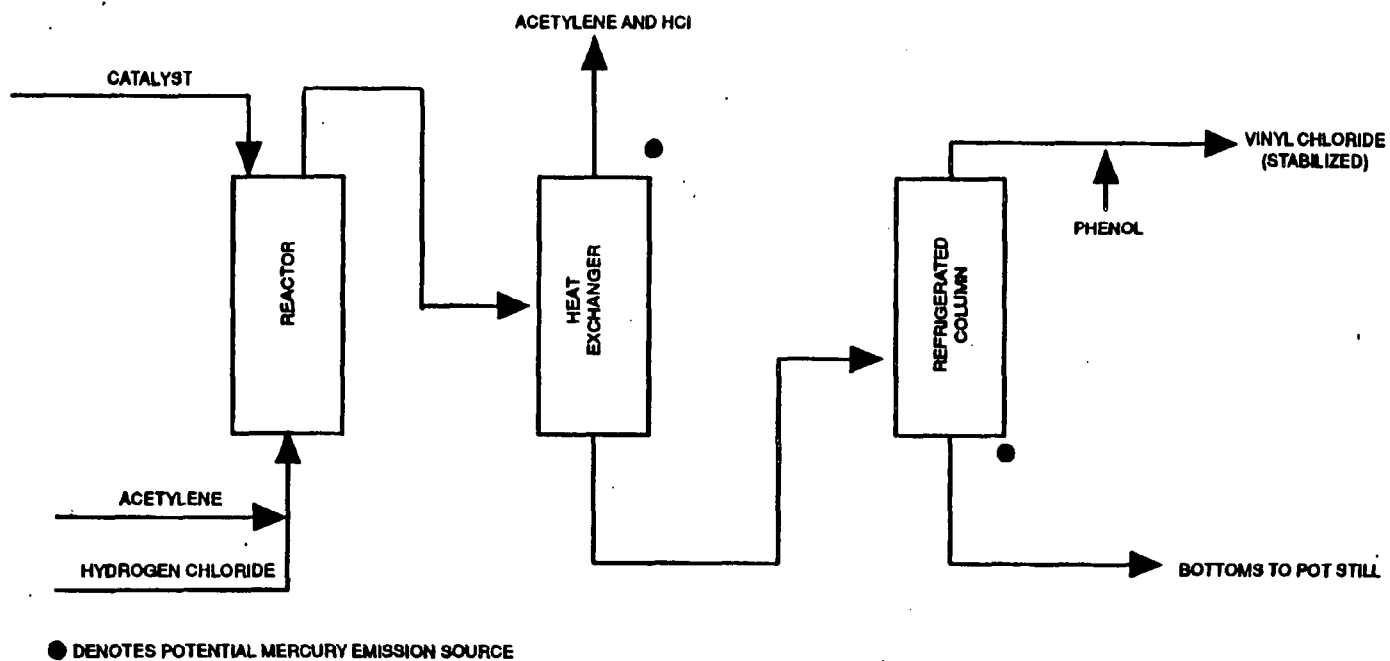


Figure 8-1. Vinyl chloride process using a mercuric chloride catalyst.¹⁰¹

anhydrous hydrogen chloride, and 131 Mg (144 tons) of mercuric chloride impregnated carbon pellets. The yield is 80 to 85 percent vinyl chloride.¹⁰¹ This reaction occurs when the anhydrous hydrogen chloride and acetylene are mixed in a reactor vessel with the mercuric chloride catalyst contained on carbon pellets. Since the reaction is exothermic, the effluent gases are cooled by heat exchange, and then condensed and fractionated in a refrigerated column. Further fractionation in another refrigerated column will remove the vinyl chloride for stabilization with phenol and storage.¹⁰¹

8.1.2 Emission Control Measures

No specific information was found in the literature concerning specific control measures for mercury emissions. The use of a heat exchange and refrigeration column in the production process will provide for a significant reduction in mercury emissions, particularly in the refrigerated column.

8.1.3 Emissions

In Figure 8-1, if the heat exchanger is operated at a low temperature, mercury condensation will occur and eventually be found in the bottoms. However, if the temperature is not sufficient to provide for condensation, an appreciable quantity of the mercury from the reactor will be entrained with the acetylene and HCl.

No emission factors were found in the literature, and no test data that could be used to calculate emission factors was found. In the 1990 TRI inventory, Borden Chemical and Plastics reported no mercury emissions at the Louisiana production facility.⁵

8.2 DENTAL ALLOYS

Dental amalgams used to fill cavities in teeth include an appreciable quantity of mercury. The amalgamation process is fairly generic industrywide, although some dental facilities use ready-made dental capsules to reduce worker exposure to elemental mercury.¹⁵

Dental fillings contain mixtures of metals, usually silver (67 to 70 percent), tin (25 to 28 percent), copper (0 to 5 percent), and zinc (0 to 2 percent), which are blended with mercury in a 5:8 proportion to form an amalgam.¹⁵

8.2.1 Process Description

The dental alloy and mercury are placed inside a two-part plastic capsule that contains a pestle. Mercury is added with a dispenser that delivers a drop (or "spill") when a button is pressed. Usually, only one or two drops are necessary to mix the amalgam. The plastic capsule is then closed and placed in an agitator where the contents are mixed for approximately 15 seconds. Once mixing is completed, the capsule is opened to remove the amalgam, which is then placed in a container for immediate application in the cavity.¹⁵

8.2.2 Emission Control Measures

There are no emission controls noted for handling mercury used in amalgam production. One work practice is the use of ready-made dental capsules that already contain a pestle and premeasured amounts of mercury and alloy.¹⁵ This would eliminate any unnecessary handling and accidental spilling of mercury.

8.2.3 Emissions

According to the Bureau of Mines (1991), industrial consumption of mercury for dental equipment and supplies was 27 Mg (30 tons).¹⁰⁰ A study in 1980 estimated that approximately 2 percent of the mercury used in dental preparations would be emitted due to spills and scrap.¹⁰² This corresponds to an emission factor of 20 kg/Mg (40 lb/ton) of mercury used. The percentage of the total quantity of mercury in dental equipment and supplies that is used for dental alloys is not known.

8.3 MOBILE SOURCES

Gasoline-powered motor, on-road, light-duty vehicles comprise the most significant mobile emission sources. According to the Motor Vehicle Manufacturers Association (MVMA), the total distance travelled for all vehicles in the U.S. in 1990 was 3,457,478 million kilometers (2,147,501 million miles).¹⁰³

8.3.1 Emissions

Historically, the major emissions measured from mobile sources are CO, NO_x, and hydrocarbons (HC); AP-42, Volume II compiles emission factors for these specific pollutants among the different motor vehicle classes. A 1983 study indicated an estimated mercury emission factor of 1.3×10^{-3} milligram (mg) per kilometer (km) (4.6×10^{-9} lb/mile) for motor vehicles without resolution of emission rates into vehicle types.¹⁰⁴ The population of vehicles studied was 81.9 percent gasoline-powered passenger cars, 2.4 percent gasoline-powered trucks, and 15.7 percent diesel trucks. This emission factor should be used cautiously as it was based on a 1977 ambient sampling study, which was before the widespread use of catalytic converters and unleaded gasoline, and before State-regulated inspection and maintenance programs were widely mandated. In 1977,

diesel-powered vehicles had not yet been regulated for emission controls, especially for particulates.

A 1979 study characterized regulated and unregulated exhaust emissions from catalyst and non-catalyst equipped light-duty gasoline operated automobiles operating under malfunction conditions.¹⁰⁵ An analysis for mercury was included in the study but no mercury was detected. The analytical minimum detection limit was not stated.

A more recent 1989 study measured the exhaust emission rates of selected toxic substances for two late model gasoline-powered passenger cars.¹⁰⁶ The two vehicles were operated over the Federal Test Procedure (FTP), the Highway Fuel Economy Test (HFET), and the New York City Cycle (NYCC). Mercury was among the group of metals analyzed but was not present in detectable quantities. The analytical minimum detection limits for mercury in the three test procedures were: FTP 0.025 mg/km (8.9×10^{-8} lb/mile) HFET 0.019 mg/km (6.7×10^{-8} lb/mi), and NYCC 0.15 mg/km (53.2×10^{-8} lb/mi).¹⁰⁷ These minimum detection limits are over ten times higher than the estimated emission factor presented in the 1983 study.

8.4 CREMATORIES

Mercury resulting from the thermal instability of mercury alloys of amalgam tooth fillings during cremation of human bodies may potentially be a source of mercury air emissions. In 1991, there were about 400,500 cremations in the slightly more than 1,000 crematories located throughout the United States.¹⁰⁸ Table 8-1 lists the number of crematories located in each State and the estimated number of cremations performed in each State. No information was available on the location of individual crematories.¹⁰⁹

TABLE 8-1. 1991 U.S. CREMATORY LOCATIONS BY STATE

State	No. of crematories	No. of cremations ^a	State	No. of crematories	No. of cremations
Alabama	6	1,138	Montana	12	2,502
Alaska	7	790	Nebraska	6	1,139
Arizona	26	10,189	Nevada	11	5,009
Arkansas	13	1,787	New Hampshire	6	1,842
California	141	86,374	New Jersey	16	14,427
Colorado	28	7,432	New Mexico	9	2,134
Connecticut	10	4,260	New York	40	23,946
Delaware	4	1,165	North Carolina	24	4,749
District of Columbia	1	b	North Dakota	1	b
Florida	95	46,775	Ohio	41	12,552
Georgia	14	2,684	Oklahoma	9	1,372
Hawaii	10	3,495	Oregon	34	9,020
Idaho	12	1,949	Pennsylvania	44	12,153
Illinois	44	12,083	Rhode Island	5	1,842
Indiana	21	3,636	South Carolina	10	1,764
Iowa	15	2,241	South Dakota	4	b
Kansas	10	1,559	Tennessee	8	1,712
Kentucky	5	1,192	Texas	36	9,340
Louisiana	6	1,853	Utah	5	769
Maine	4	2,656	Vermont	5	1,570
Maryland	17	5,587	Virginia	25	6,097
Massachusetts	13	8,104	Washington	46	15,673
Michigan	38	13,431	West Virginia	6	582
Minnesota	18	5,662	Wisconsin	29	5,541
Mississippi	4	450	Wyoming	2	b
Missouri	19	4,637			

^a1990 data. 1991 data unavailable.

^bNo information available.

Source: Reference 108.

No data are available for the average quantity of mercury emitted for a cremation in the United States. Only three estimated levels have been cited for European countries (Switzerland, Germany, and the UK) with an estimated emission of one gram of mercury per cremation recommended as a typical value.¹¹⁰ This emission factor is not considered to be applicable to cremations in the United States. There is a substantial difference in the frequency of cremations in Europe compared to the United States. In addition, there is a considerable variation in the overall dental care programs in the United States compared to Europe which may result in a difference in the average number of mercury amalgam fillings per person. The average number of fillings per person and the average mercury content per filling have a direct impact on the estimated mercury emissions. The considerable potential differences between the United States and Europe precludes an accurate estimate of mercury emissions from this source.

8.5 PAINT USE

Four mercury compounds--phenylmercuric acetate, 3-(chloromethoxy) propylmercuric acetate, di(phenylmercury) dodecenylsuccinate, and phenylmercuric oleate--have been registered as biocides for interior and exterior paint.¹¹¹ Surface application of paints using these compounds resulted in an estimated 13.2 Mg (14.6 tons) of mercury emissions into the atmosphere in 1990 and 4 Mg (5 tons) in 1991.

Mercury compounds are added to paints to preserve the paint in the can by controlling microbial growth and to preserve the paint film from mildew attack after it is applied to a surface. During and after application of paint, these mercury compounds can be emitted into the atmosphere. One source estimates that 66 percent of the mercury used in paints is emitted into the atmosphere; however, this emission rate, which was derived using engineering judgement, is based on a 1975 study performed when

the demand for mercury in paint was high.¹⁰ The age of the data and the method by which the emission factor was calculated limit the reliability of the factor, making emission estimates generated from it quite uncertain. Furthermore, no conclusive information is available regarding the time frame over which mercury in paint is emitted into the atmosphere after it is applied to a surface. However, limited information suggests that emissions could occur for as long as 7 years after initial application, although the distribution of emissions over this time period is unknown.¹¹²

As of May 1991, all registrations for mercury biocides used in paints were voluntarily canceled by the registrants, thus causing a drastic decrease in the use of mercury in paint.¹¹³ For example, the paint industry's demand for mercury in 1989 was 192 Mg (211 tons) but fell to 6 Mg (7 tons) in 1991.¹⁰⁰ Note that emission estimates presume that all mercury emissions are generated from paint application in the year that the paint is produced.

8.6 SOIL DUST

Mercury levels in soil dust have been measured at a few locations in the western United States.⁹⁴ The mercury level in soil dust near a phosphate fertilizer operation in Pocatello, Idaho was found to be 0.002 (20 ppm) weight percent and levels in dust from an unpaved road near the same facility were at 0.001 weight percent. This reference also cited mercury levels to be about 0.001 weight percent in soil dust near a courthouse in Medford, Oregon; at a school in Bend, Oregon; near the downtown area of Grant's Pass, Oregon; and near Key Back in Eugene, Oregon. Samples taken near a silicone manufacturing plant in Springfield, Oregon, showed mercury levels at 0.004 weight percent in the soil dust. Tests at LaGrande dock in LaGrande, Oregon, showed mercury in the soil dust at levels of 0.003 weight percent.

The validity of these levels cannot be verified because the original references could not be located to evaluate the test methods and procedures used in these studies. In addition, the mercury levels found in the soils of these areas probably are not indicative of soil levels in other areas of the country. The soils in the Idaho and Oregon areas are primarily volcanic in geologic origin and have higher soil mercury levels than other areas of the U.S.

8.7 NATURAL SOURCES OF MERCURY EMISSIONS

Mercury is emitted from natural sources (rock, soils, water and biota) primarily as elemental mercury vapor and to a lesser degree as particulate and vaporous oxides, sulfides and halides of mercury. Organomercuric compounds (methylmercury vapors) are also a significant component of natural emissions (some evidence of dimethyl-mercury emissions also exists).¹¹⁴ However, few direct measurements of mercury flux and speciation from natural sources are available in the literature. There is general agreement that the principal natural sources of mercury emissions include, in order of probable importance, volatilization in marine and other aquatic environments, volatilization from vegetation, degassing of geologic materials, particulate matter (PM) and vapor emissions during volcanic and geothermal activity, wind-blown dust, and PM and vapor emissions during forest and brush fires. Recent studies strongly emphasize the importance of the air-water exchange of mercury as well as biologically mediated volatilization in both marine and terrestrial environments.¹¹⁴⁻¹¹⁷ These sources represent a relatively constant flux to the atmosphere and may comprise 30 to 50 percent of total natural emissions.¹¹⁷ In contrast, volcanic, geothermal, and burning biomass activities are widely variable temporally and spatially. Volcanic eruptions, in particular, can cause massive perturbations in atmospheric trace metal cycles. Volcanic activity alone may comprise 40 to 50 percent of total natural mercury emissions at times.¹¹⁷

Published estimates of total global emissions of mercury from natural sources range widely from 100 to 30,000 megagrams (Mg) (110 to 33,000 tons) per year. However, the more recent estimates cluster in the 2,000 to 3,000 Mg per year range.¹¹⁴⁻¹¹⁷ Lindqvist, citing work done in 1988, estimated natural emissions to be 3,000 Mg (3,300 tons) per year or approximately 40 percent of total global emissions from all sources.¹¹⁴ The supporting data for individual source categories are limited for each of these estimates, and it is clear that any quantitative understanding of natural mercury flux is lacking.

As a result of reemission, current levels of mercury emitted to the atmosphere by natural processes are elevated relative to preindustrial levels. More than two thirds of world mercury production has occurred since 1900, and mercury emissions have been widely dispersed and recycled. In other words, present day emissions from natural sources are comprised of a yesterday's anthropogenic emissions, in part. It is not possible to quantify the contribution of recycled mercury to the natural emissions estimates and, therefore, the estimates cited above must be viewed with even greater uncertainty.

SECTION 9

SOURCE TEST PROCEDURES

9.1 INTRODUCTION

A number of methods exist to determine mercury emissions from stationary sources. Several EPA offices and some State agencies have developed source specific or dedicated sampling methods for Hg. Other industry sampling methods do exist, but none of these methods have been validated and will not be discussed in this section.

Subsequent parts of this section discuss EPA reference or equivalent sampling methods for Hg. Sampling methods fall into one of two categories: (1) dedicated Hg methods for specific sources or, (2) multiple metals sampling trains that include Hg for multiple sources. Each category of methods will be described, differences among the methods will be discussed, and a citation provided for more detailed information about the methods. A summary of methods is presented in Table 9-1.

Sampling methods included in this section were selected from EPA reference methods, draft methods, or State methods. To be a reference method, a sampling method must undergo a validation process and be published. To qualify as an equivalent method, a sampling method must be demonstrated to the EPA Administrator, under specific conditions, as an acceptable alternative to the normally used reference methods. Also included in this section is a draft method, which is under development.

TABLE 9-1. MERCURY SAMPLING METHODS

Method	Filter	Impinger	Range	Chemical interference	Detection limit
EPA 101	None	3 X ICI 1 X silica gel	0.5 to 120 $\mu\text{g Hg/ml}$	SO_2	Not listed
EPA 101A	Glass fiber (optional)	1 X KMnO_4 2 X KMnO_4 1 X silica gel	20-800 ng Hg/ml	Oxidizable organic matter, Water vapor on optical window	Not listed
EPA 102	None	3 X ICI 1 X silica gel	0.5 to 120 $\mu\text{g Hg/ml}$	SO_2	Not listed
EPA 29 (Draft)	Quartz or glass fiber	1 X empty (optional) 2 X $\text{HNO}_3/\text{H}_2\text{O}_2$ 1 X empty 2 X $\text{KMnO}_4/\text{H}_2\text{SO}_4$ 1 X silica gel	ngHg/ml to $\mu\text{g Hg/ml}$	None	0.2 ng Hg/ml
SW-846 0012	Quartz or glass fiber	1 X empty (optional) 2 X $\text{HNO}_3/\text{H}_2\text{O}_2$ 1 X empty 2 X $\text{KMnO}_4/\text{H}_2\text{SO}_4$ 1 X silica gel	ngHg/ml to $\mu\text{g Hg/ml}$	None	0.2 ng Hg/ml
OSW-BIF	Quartz or glass fiber	1 X empty 2 X $\text{HNO}_3/\text{H}_2\text{O}_2$ 1 X empty 2 X $\text{KMnO}_4/\text{H}_2\text{SO}_4$ 1 X silica gel	ngHg/ml to $\mu\text{g Hg/ml}$	None	0.2 ng Hg/ml
CARB 436	Quartz or glass fiber	1 X empty 2 X $\text{HNO}_3/\text{H}_2\text{O}_2$ 2 X $\text{KMnO}_4/\text{H}_2\text{SO}_4$ 1 X silica gel	ngHg/ml to $\mu\text{g Hg/ml}$	None	0.2 ng Hg/ml

9.2 DEDICATED MERCURY SAMPLING METHODS

9.2.1 EPA Method 101-Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants¹¹⁸

This method applies to the determination of particulate and gaseous Hg emissions from chlor-alkali plants and other sources (as specified in the regulations), where the carrier-gas stream in the duct or stack is principally air. Particulate and gaseous Hg emissions are withdrawn isokinetically from the source and collected in an acidic iodine monochloride (ICl) solution. The Hg collected (in the mercuric form) is reduced to elemental Hg and then aerated and precipitated from the solution into an optical cell and measured by atomic absorption spectrophotometry (AAS). A diagram of a sampling train typical of dedicated Hg sampling trains is presented in Figure 9-1.

After initial dilution, the range of this method is 0.5 to 120 micrograms of Hg per milliliter ($\mu\text{g Hg/ml}$). The upper limit can be extended by further dilution of the sample. The sensitivity of this method depends on the selected recorder/spectrophotometer combination.

Analytical interferences include SO_2 which reduces ICl and causes premature depletion of the ICl solution. Also, concentrations of ICl greater than 10^{-4} molar inhibit the reduction of the Hg(II) ion in the aeration cell. Condensation of water vapor on the optical cell windows of the AAS causes a positive interference.

Estimates of precision and accuracy were based on collaborative tests, wherein 13 laboratories performed duplicate analyses on two Hg-containing samples from a chlor-alkali plant and on one laboratory-prepared sample of known Hg concentration.

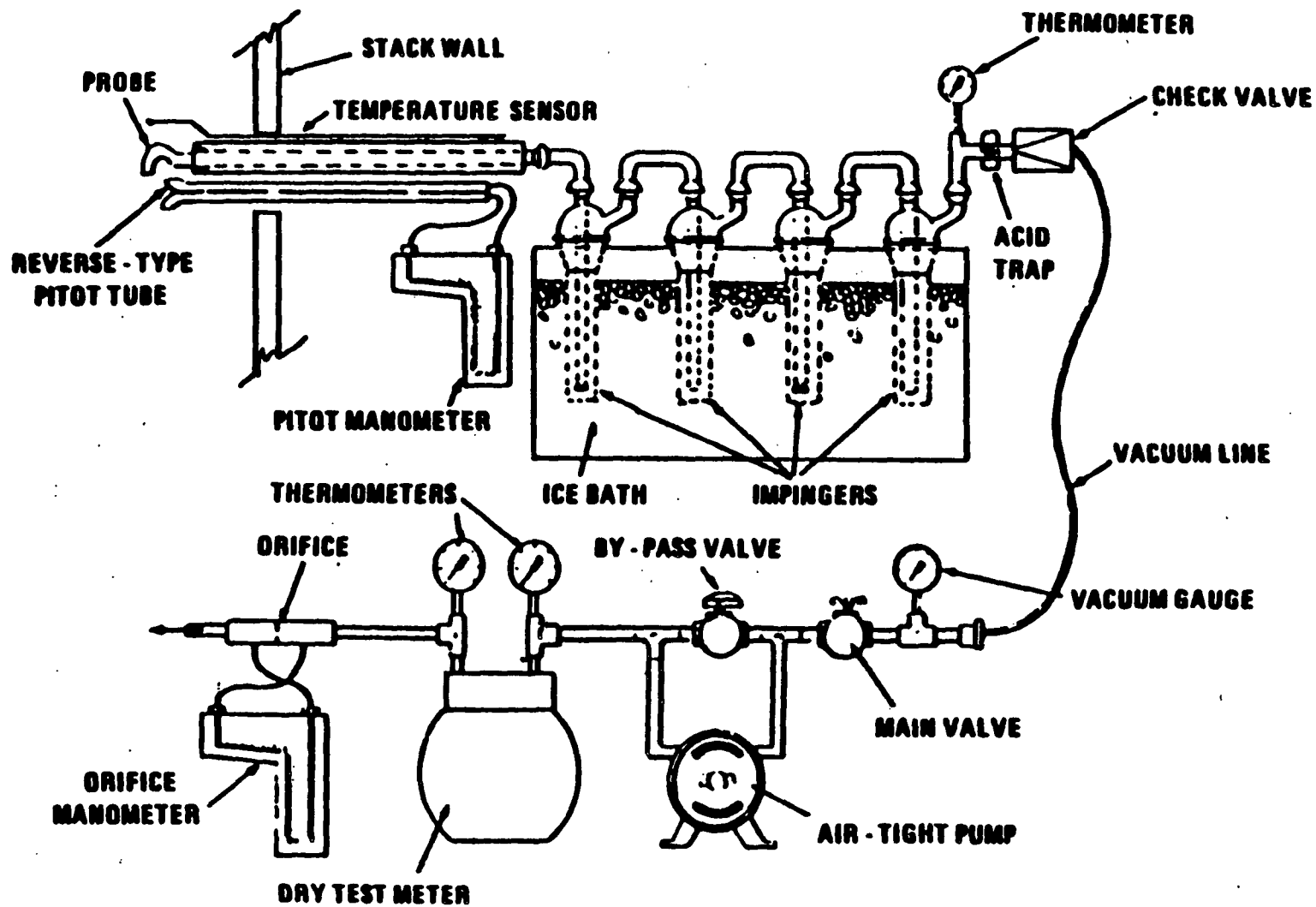


Figure 9-1. Typical dedicated mercury sampling train.

The estimated within-laboratory and between-laboratory standard deviations are 1.6 and 1.8 $\mu\text{g Hg/ml}$, respectively.

9.2.2 EPA Method 101A-Determination of Particulate and Gaseous Mercury Emissions from Sewage Sludge Incinerators¹¹⁹

This method is similar to Method 101, except acidic potassium permanganate (KMnO_4) solution is used for collection instead of acidic ICl . This method applies to the determination of particulate and gaseous Hg emissions from sewage sludge incinerators and other sources as specified in the regulations.

Particulate and gaseous Hg emissions are withdrawn isokinetically from the source and collected in acidic KMnO_4 solution. The Hg collected (in the mercuric form) is reduced to elemental Hg, which is then aerated from the solution into an optical cell and measured by AAS.

After initial dilution, the range of this method is 20 to 800 nanograms of Hg per milliliter (ng Hg/ml). The upper limit can be extended by further dilution of the sample. The sensitivity of the method depends on the selected recorder/spectrophotometer combination.

Analytical interferences include excessive oxidizable organic matter in the stack gas, which prematurely depletes the KMnO_4 solution, and thereby prevents further collection of Hg. Condensation of water vapor on the optical cell windows of the AAS causes a positive interference.

Based on eight paired-train tests, the within-laboratory standard deviation was estimated to be 4.8 $\mu\text{g Hg/ml}$ in the concentration range of 50 to 130 micrograms of Hg per cubic meter ($\mu\text{g Hg/m}^3$).

9.2.3 EPA Method 102-Determination of Particulate and Gaseous Mercury Emissions from Chlor-Alkali Plants-Hydrogen Streams¹²⁰

Although similar to Method 101, Method 102 requires changes to accommodate the sample being extracted from a hydrogen stream. Sampling is conducted according to Method 101, except:

1. Operate only the vacuum pump during the test. The other electrical equipment, e.g., heaters, fans, and timers, normally are not essential to the success of a hydrogen stream test.

2. Calibrate the orifice meter at flow conditions that simulate the conditions at the source as described in APTD-0576 (see Citation 9 in Section 10 of Method 101). Calibration should either be done with hydrogen or with some other gas having a similar Reynolds Number so that there is a similarity between the Reynolds Numbers during calibration and during sampling.

9.3 MULTIPLE METALS SAMPLING TRAINS

9.3.1 Method 0012-Methodology for the Determination of Metals Emissions in Exhaust Gases from Hazardous Waste Incineration and Similar Combustion Sources¹²¹

Two other multiple metals sampling methods developed by EPA exist that can be used to collect Hg. These methods are the Methodology for the Determination of Metals Emissions in Exhaust Gases from Hazardous Waste Incineration and Similar Combustion Sources and EPA Method 29-Methodology for the Determination of Metals Emissions in Exhaust Gases from Incineration and Similar Combustion Sources (Draft).^{122,123} Both methods are virtually identical to Method 0012 in sampling approach and analytical requirements.

This method was developed for the determination of a total of 16 metals, including Hg, from stack emissions of hazardous waste incinerators and similar combustion processes. Method 0012 allows for the determination of particulate emissions from these sources; however, the filter heating/desiccation modifications to the sample recovery and analysis procedures described in this protocol for the purpose of determining particulate emissions may potentially impact the front-half Hg determination. A diagram of a sampling train typical of a multiple metals sampling train is presented in Figure 9-2.

The stack sample is withdrawn isokinetically from the source. Particulate emissions are collected in the probe and on a heated filter; gaseous emissions are collected in a series of moisture knockout traps, chilled impingers, and silica gel traps. Of the four solution charged impingers, two contain an aqueous solution of dilute nitric acid (HNO_3) combined with dilute hydrogen peroxide (H_2O_2) and two contain acidic potassium permanganate (KMnO_4) solution. Materials collected in the sampling train are digested with acid solutions using conventional Parr® Bomb, or microwave digestion techniques to dissolve inorganics and to remove organic constituents that may create analytical interferences. As many as six separate samples can be recovered from the sampling train. The $\text{HNO}_3/\text{H}_2\text{O}_2$ impinger solution, the acidic KMnO_4 impinger solution, the hydrochloric acid (HCl) rinse solution, the acid probe rinse, the acetone probe rinse, and digested filter solutions can be analyzed for Hg by cold vapor atomic absorption spectroscopy (CVAAS). As few as three sample fractions can be analyzed for Hg; the combined probe rinse and filter, the combined $\text{HNO}_3/\text{H}_2\text{O}_2$ impinger solutions, and the combined KMnO_4 impinger and rinse solutions. The detection limit for Hg by CVAAS is approximately 0.2 ng Hg/ml.

The corresponding in-stack method detection limit can be calculated by using (1) the procedures described in this method, (2) the analytical detection limits described in the previous

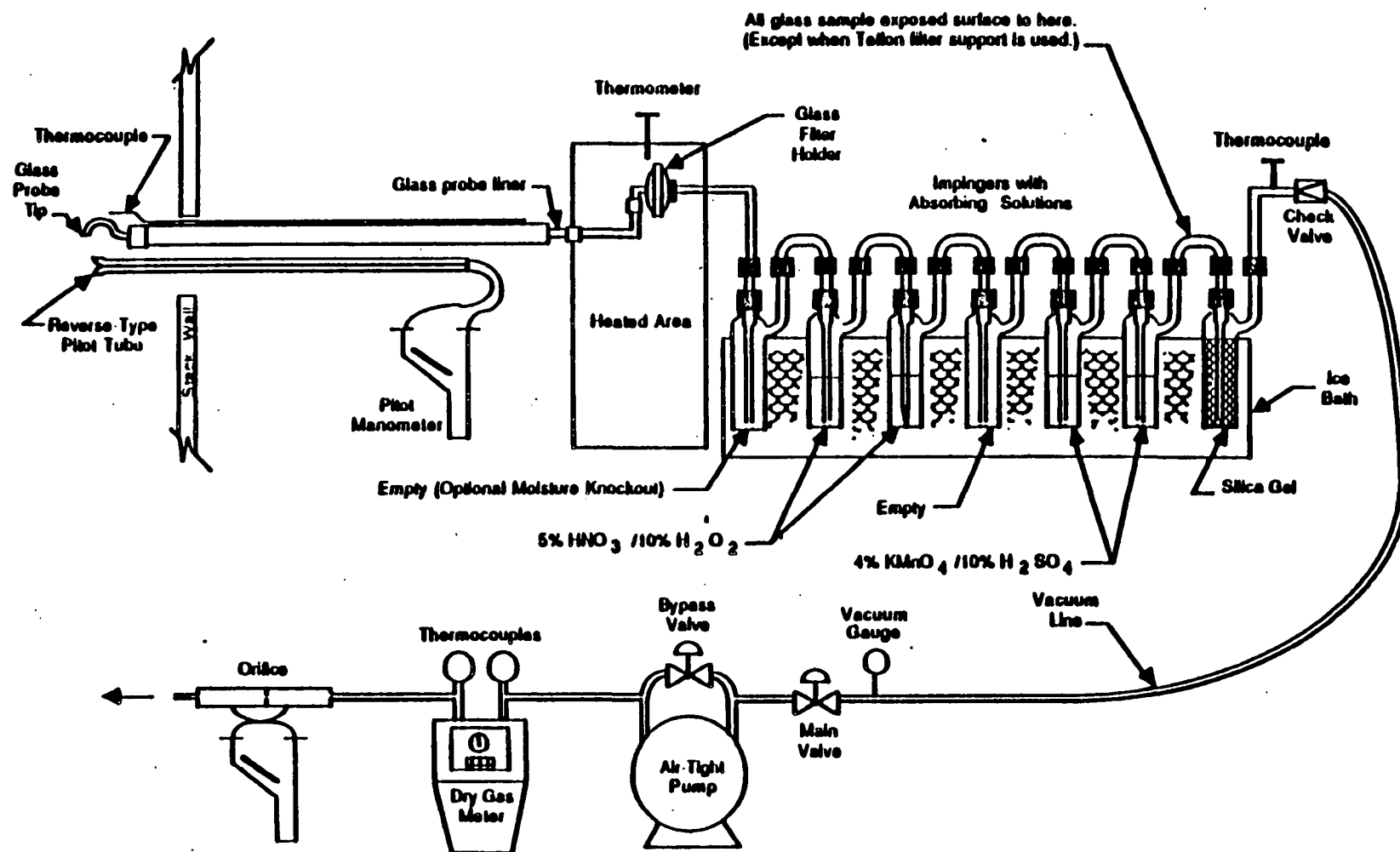


Figure 9-2. Typical multiple metals sampling train.

paragraph, (3) a volume of 300 ml for the front-half and 150 ml for the back-half samples, and (4) a stack gas sample volume of 1.25 m³:

$$\frac{A \times B}{C} = D$$

where: A = analytical detection limit, µg Hg/ml
B = volume of sample prior to aliquot for analysis, ml
C = sample volume, dry standard cubic meter (dscm)
D = in-stack detection limit, µg Hg/m³

The in-stack method detection limit for Hg using CVAAS based on this equation is 0.07 µg Hg/m³ for the total sampling train. A similar determination using AAS is 5.6 µg Hg/m³.

9.3.2 CARB Method 436-Determination of Multiple Metals Emissions from Stationary Sources¹²⁴

This method is applicable for determining the emissions of metals, including Hg, from stationary sources. This method is similar to SW-846 Method 0012 in sampling approach and analytical requirements. Method 436 suggests that the concentrations of target metals in the analytical solutions be at least 10 times the analytical detection limits. This method may be used in lieu of Air Resource Board Methods 12, 101, 104, 423, 424, and 433.

9.4 ANALYTICAL METHODS FOR DETERMINATION OF MERCURY^{125,126}

This section contains brief descriptions of two analytical techniques generally used for Hg determinations.

The two Hg analysis methods are Method 7470 and 7471, from SW-846. Both methods are cold-vapor atomic absorption methods, based on the absorption of radiation at the 253.7-nm wavelength by mercury vapor. Mercury in the sample is reduced to the elemental state and aerated from solution in a closed system.

The Hg vapor passes through a cell positioned in the light path of an atomic absorption spectrophotometer. Absorbance (peak height) is measured as a function of mercury concentration. Cold-Vapor AA (CVAA) uses a chemical reduction to selectively reduce Hg. The procedure is extremely sensitive but is subject to interferences from some volatile organics, chlorine, and sulfur compounds. The typical detection limit for these methods is 0.0002 mg/L.

The two methods differ in that Method 7470 is approved for analysis of Hg in mobility-procedure extracts, aqueous wastes, and ground waters. Method 7471 is approved for analysis of Hg in soils, sediments, bottom deposits, and sludge-type materials. Analysis of samples containing high amounts of organic present special problems: (1) likely to foam during the reduction step and block the flow of sample to the absorption cell and (2) have high reducing capability and can reduce Hg(II) to Hg before addition of stannous chloride (SnCl_2).

Two analytical considerations are common to both methods. stannous chloride should be added immediately prior to analysis to ensure the reduction of Hg(II) to Hg occurs in the vaporization cell only. Second, moisture in the absorption cell can reduce the reliability of the method and should be eliminated or minimized. Finally, a closed-loop system may provide a more reliable system than an open-loop system for introduction of the sample to the reaction flask.

9.5 SUMMARY

All of the above source sampling methods collect a sample for analysis of multiple metals, including Hg, or a sample for Hg analysis alone. Significant criteria and characteristics of each method are presented in Table 9-1. This table is a summary of information presented in various methods. The major differences between the methods involve: (1) the type of impinger solutions,

(2) the amount or concentration of impinger solutions, (3) the sequence and types of sample train recovery solutions, and (4) the use and/or type of particulate filter.

In assessing Hg emissions from test reports, the age or revision number of the method indicates the level of precision and accuracy of the method. Older methods are sometimes less precise or accurate than those that have undergone more extensive validation. Currently, EPA Method 301 from 40 CFR Part 63, Appendix A can be used to validate or prove the equivalency of new methods.

SECTION 10

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APPENDIX A.
NATIONWIDE EMISSION ESTIMATES

EMISSIONS FROM MERCURY PRODUCTION

Secondary Mercury Production

Basis of Input Data

1. Emission factor of 20 kg of Hg/Mg Hg produced.¹
2. 1990 production from industrial and governmental sources was 286 Mg.²
3. Emissions from secondary mercury production are uncontrolled.
4. Emissions due to chemical and thermal treatment are equal.

Calculation

Annual emission = $20 \text{ kg/Mg} * 286 \text{ Mg} = 5.7 \text{ Mg/yr} =$
6.3 tons/yr

EMISSIONS FROM MAJOR USES OF MERCURY

Chlor-Alkali Production

Basis of Input Data

1. In 1990 TRI summary, 17 of the 18 mercury cell facilities reported air emissions of mercury.³
2. The total quantity of mercury emissions from 17 facilities was 8.74 Mg (9.6 tons).
3. Emission data were prorated for the remaining facility.

Calculation

Annual emissions = $18/17 * 8.74 \text{ Mg/yr} = 9.3 \text{ Mg/yr} = 10.2 \text{ tons/yr}$

Battery Manufacture

Basis of Input Data

1. The 1990 consumption of mercury in the production of primary batteries was 106 Mg (117 tons).²
2. A mercury emission factor of 1.0 kg/Mg used (2.0 lb/ton) was obtained from a Wisconsin study of a mercury oxide battery plant, which is the only type of battery using mercury.⁴
3. Another mercury emission factor of 5.6 kg/Mg (11.2 lb/ton) has been cited but the source and reliability of this factor could not be verified.⁵
4. The emission factor based on TRI data may give abnormally high values because the TRI data includes abnormal and accidental releases.

Calculation

Wisconsin study --

Annual emissions = $1.0 \text{ kg/Mg} * 106 \text{ Mg} = 106 \text{ kg/yr} = 0.11 \text{ Mg/yr} = 0.12 \text{ ton/yr}$

Electrical Uses

Electric lighting --

Basis of Input Data

1. The 1990 consumption of mercury was 33 Mg (36 tons).²
2. No emission factor is available for the manufacture of electric lamps.
3. The only mercury emission information available is due to lamp breakage of outdoor and indoor lamps.
4. It is assumed that 50 percent of the mercury used in lamps was for outdoor lamps and 50 percent for indoor lamps.
5. Of the mercury used in outdoor lamps, 33 percent will be released to the atmosphere and 22 percent from the indoor lamps.¹

Calculation

Outdoor lamps --

Annual emission = $33 \text{ Mg} * 0.5 * 0.33 = 5.4 \text{ Mg/yr} = 6.0 \text{ tons/yr}$

Indoor lamps --

Annual emissions = $33 \text{ Mg} * 0.5 * 0.22 = 3.6 \text{ Mg/yr} = 4 \text{ tons/yr}$

EMISSIONS FROM COMBUSTION SOURCES

Coal Combustion

Coal-Fired Utility Boilers--

Basis of Input Data

1. From Table 6-8, emission factor for bituminous coal combustion = $7.0 \times 10^{-15} \text{ kg/J}$ and for anthracite coal combustion = $7.6 \times 10^{-15} \text{ kg/J}$.
2. Bituminous coal combustion systems controlled by ESP's with an average mercury control efficiency of 25 percent.
3. Anthracite coal combustion systems uncontrolled.

4. Energy from coal combustion in utility sector from Table 6-1.

Calculations

$$\begin{aligned}\text{Annual Emissions} &= 7.0 \times 10^{-15} \text{ kg/J} * 16.939 \times 10^{18} \text{ J/yr} * \\ &\quad 0.75 \\ &\quad + 7.6 \times 10^{-15} \text{ kg/J} * 0.018 \times 10^{18} \text{ J/yr} \\ &= 89.07 \text{ Mg/yr} = 97.98 \text{ tons/yr}\end{aligned}$$

Coal-Fired Industrial Boilers--

Basis of Input Data

1. From Table 6-8, emission factor for bituminous coal combustion = 7.0×10^{-15} kg/J and for anthracite coal combustion = 7.6×10^{-15} kg/J
2. No control of emissions from industrial boilers was assumed.
3. Energy from coal combustion in industrial sector from Table 6-1.

Calculations

$$\begin{aligned}\text{Annual Emissions} &= 7.0 \times 10^{-15} \text{ kg/J} * 2.892 \times 10^{18} \text{ J/yr} \\ &\quad + 7.6 \times 10^{-15} \text{ kg/J} * 0.009 \times 10^{18} \text{ J/yr} \\ &= 20.31 \text{ Mg/yr} = 22.34 \text{ ton/yr}\end{aligned}$$

Coal-Fired Commercial and Residential Boilers- -

Basis of Input Data

1. From Table 6-8, emission factor for bituminous coal combustion = 7.0×10^{-15} kg/J and for anthracite coal combustion = 7.6×10^{-15} kg/J
2. No control of emissions from commercial/residential boilers was assumed.
3. Energy from coal combustion in commercial/residential sectors from Table 6-1.

Calculations

$$\begin{aligned}\text{Annual Emissions} &= 7.0 \times 10^{-15} \text{ kg/J} * 0.130 \times 10^{18} \text{ J/yr} \\ &\quad + 7.6 \times 10^{-15} \text{ kg/J} * 0.032 \times 10^{18} \text{ J/yr} \\ &= 1.15 \text{ Mg/yr} = 1.27 \text{ tons/yr}\end{aligned}$$

Oil Combusion

Oil-Fired Utility Boilers--

Basis of Input Data

1. From Table 6-15, emission factor for distillate oil combustion = 2.9×10^{-15} kg/J and for residual oil combustion = 3.0×10^{-15} kg/J
2. Air pollution control measures assumed to provide no mercury emission reduction.
3. Energy consumption from fuel oil combustion from Table 6-1.

Calculations

$$\begin{aligned}\text{Annual Emissions} &= 2.9 \times 10^{-15} \text{ kg/J} * 1.201 \times 10^{18} \text{ J/yr} \\ &\quad + 3.0 \times 10^{-15} \text{ kg/J} * 0.091 \times 10^{18} \text{ J/yr} \\ &= 3.76 \text{ Mg/yr} = 4.14 \text{ tons/yr}\end{aligned}$$

Oil-Fired Industrial Boilers--

Basis of Input Data

1. From Table 6-15, emission factor for distillate oil combustion = 2.9×10^{-15} kg/J and for residual oil combustion = 3.0×10^{-15} kg/J
2. Air pollution control measures assumed to provide no mercury emission reduction.
3. Energy consumption from fuel oil combustion from Table 6-1.

Calculations

$$\begin{aligned}\text{Annual Emissions} &= 2.9 \times 10^{-15} \text{ kg/J} * 1.245 \times 10^{18} \text{ J/yr} \\ &\quad + 3.0 \times 10^{-15} \text{ kg/J} * 0.436 \times 10^{18} \text{ J/yr} \\ &= 4.92 \text{ Mg/yr} = 5.42 \text{ tons/yr}\end{aligned}$$

Oil-Fired Commercial/Residential Boilers--

Basis of Input Data

1. From Table 6-15, emission factor for distillate oil combustion = 2.9×10^{-15} kg/J and for residual oil combustion = 3.0×10^{-15} kg/J
2. Air pollution control measures assumed to provide no mercury emission reduction.

3. Energy consumption from fuel oil combustion from Table 6-1.

Calculations

$$\begin{aligned}\text{Annual Emissions} &= 2.9 \times 10^{-15} \text{ kg/J} * 1.395 * 10^{18} \text{ J/yr} \\ &\quad + 3.0 \times 10^{-15} \text{ kg/J} * 0.255 * 10^{18} \text{ J/yr} \\ &= 4.81 \text{ Mg} = 5.30 \text{ tons/yr}\end{aligned}$$

Wood Combustion in Boilers--

Basis of Input Data

1. Wood combustion rate in boilers is 1.0×10^{11} Btu/hr, which is the same rate as 1980 given on p. 6-37. Boilers assumed to operate at capacity, 8,760 hr/yr.
2. Heating value of wood is 4,500 Btu/lb based on midpoint of range presented on p. 6-37.
3. Emission factor of 6.5×10^{-6} lb/ton of wood burned.
4. No control of mercury emissions.

Calculations

Annual Emissions

$$\begin{aligned}&= \frac{1.0 \times 10^{11} \text{ Btu/hr} * 8,760 \text{ hr/yr} * 6.5 \times 10^{-6} \text{ lb/tons wood}}{4,500 \text{ Btu/lb} * 2,000 \text{ lb wood/ton wood} * 2,000 \text{ lb Hg/ton Hg}} \\ &= 0.32 \text{ ton/yr} = 0.29 \text{ Mg/yr}\end{aligned}$$

Municipal Waste Combustors--

Basis of Input Data

1. Under the assumption that ESP's provide essentially no control, the facility-average concentrations at 7 percent oxygen for uncontrolled and ESP-controlled mass burn (including modular) and RDF systems contained in Table B-2 were averaged to obtain the following "typical" concentrations:

Mass Burn	- 696 $\mu\text{g/dscm}$
RDF	- 561 $\mu\text{g/dscm}$

2. The F-factor for municipal waste combustors was assumed to be 0.257×10^{-6} dscm/J at 0 percent oxygen and the heating values were assumed to be 4,500 Btu/lb for MSW and 5,500 Btu/lb for RDF (see p. 6-53). The F-factor was converted from 0 percent oxygen to 7 percent oxygen

(at which concentrations are based) using a factor of 1.5.

3. Based on a meeting with the EPA MWC project team, all modular MWC's are assumed to be controlled with ESP's.
4. Spray dryer or duct sorbent injection systems combined with fabric filters or ESP's and wet scrubber systems achieve 50 percent removal. No other control measures achieve appreciable mercury control.
5. The 1990 MWC processing rates are assumed to be equal to those presented in Waste Age, November 1991, and tabulated in the calculation table below.⁶

Calculations

Uncontrolled Emission Factors

- Mass burn/modular - $670 \mu\text{g/dscm} * 0.257 \times 10^{-6} \text{ dscm/J} * 10,500 \text{ J/g} * 1.5 = 2.71 \text{ g/Mg}$
- RDF - $527 \mu\text{g/dscm} * 0.257 \times 10^{-6} \text{ dscm/J} * 12,800 \text{ J/g} * 1.5 = 2.60 \text{ g/Mg}$

Controlled Emissions

Annual Emissions

$$= \text{Process rate} * \text{emission factor} * \frac{(100 - \text{efficiency})}{100}$$

The calculated emissions are tabulated below:

Combustor type	Control status ^a	Process rate, 10 ⁶ Mg/yr	Uncontrolled emission factor, g/Mg	Control efficiency, %	Annual Emissions	
					Mg/yr	ton/yr
Mass Burn	U	0.517	2.8	0	1.45	1.60
Mass Burn	SD	7.190	2.8	50	10.07	11.10
Mass Burn	DSI	1.077	2.8	50	1.51	1.66
Mass Burn	ESP	13.806	2.8	0	38.66	42.61
RDF	SD	2.809	2.8	50	3.93	4.34
Modular	ESP	0.630	2.8	0	2.25	2.48
Total					57.87	63.79

^aSD = Spray dryer with either ESP or fabric filter

ESP = Electrostatic precipitator

DSI = Duct sorbent injection with either ESP or fabric filter

U = Uncontrolled

Sewage Sludge Incinerators --

Basis for Input Data

1. Total sludge processed annually is 1.5×10^6 Mg (see p. 6-54)
2. From the Draft AP-42, Section 2.5, Sewage Sludge Incineration, an average emission factor for units with a venturi control device was 0.018 g/Mg (3.5×10^{-5} lb/ton).⁷ For other control devices, the average emission factor was 1.6 g/Mg (3.2×10^{-3} lb/ton).
3. In the U.S., there are 210 sewage sludge incinerators; of this population, 47 use venturi control devices, 97 use other control devices, and no information was available for 66 units.⁸ Of the 144 units for which data are available, 47/144 or 33 percent use venturi controls and 97/144 or 67 percent use other controls. This percentage distribution is assumed to be representative for all 210 units.

Calculations

$$\begin{aligned}\text{Annual Emissions} &= 1.5 \times 10^6 \text{ Mg/yr} \times 0.33 \times 0.018 \text{ g/Mg} + \\ &\quad 1.5 \times 10^6 \times 0.67 \times 1.6 \text{ g/Mg} = 1.62 \text{ Mg/yr} \\ &= 1.79 \text{ tons/yr}\end{aligned}$$

Medical Waste Incinerators --

Basis of Input Data

1. The annual emission estimates are based on a model plant calculation procedure employed in developing the environmental impacts for the New Source Performance Standard for medical waste incinerators.⁹ Uncontrolled Hg concentrations are assumed to be 3,100 $\mu\text{g/dscm}$ at 7 percent O_2 for continuous and intermittent MWI's, 2,300 $\mu\text{g/dscm}$ at 7 percent O_2 for batch MWI's, and 50 $\mu\text{g/dscm}$ at 7 percent O_2 for pathological MWI's.
2. No appreciable control of Hg emissions is achieved by existing facilities.

3. The operating characteristics and numbers of units associated with existing MWI's are:

Model No.	Type	Flow rate, dscfm at 14% O ₂	Operating hours, hr/yr	No. of units
1	Continuous	4,747	7,760	154
2	Continuous	3,165	3,564	182
3	Intermittent	4,747	4,212	171
4	Intermittent	1,899	4,212	742
5	Intermittent	633	3,588	2,097
6	Batch	455	3,520	335
7	Pathological	730	2,964	1,305

Calculations

1. Example for Model 1

Annual emissions

$$= 154 \text{ units} \cdot \frac{7,760 \text{ hr}}{\text{unit-yr}} \cdot \frac{60 \text{ min}}{\text{hr}} \cdot \frac{4,747 \text{ ft}^3}{\text{min}} \cdot \frac{1 \text{ m}^3}{35.31 \text{ ft}^3} \cdot \frac{3,100 \text{ } \mu\text{g}}{\text{m}^3} \cdot \frac{(21-7)}{(21-14)} \cdot \frac{10^{-12} \text{ Mg}}{\mu\text{g}}$$

$$= 14.94 \text{ Mg/yr} = 16.47 \text{ ton/yr}$$

2. Total emissions

Annual emissions

$$= \sum_{i=1}^7 \text{emissions for Model } i$$

$$= 14.94 + 5.41 + 9.01 + 15.63 + 12.55 + 1.05 + 0.12$$

$$= 58.7 \text{ Mg/yr} = 64.7 \text{ tons/yr}$$

EMISSIONS FROM MISCELLANEOUS MANUFACTURING PROCESSES

Portland Cement Production

Basis of Input Data

1. The 1990 total production of cement was 70.6×10^6 Mg (77.8×10^6 tons) of which 95.7 percent was portland cement. Total production of portland cement was 67.5×10^6 Mg (74.5×10^6 tons).² Portland cement is 96% clinker.

2. From Table C-2, the average emission factor is 8.7×10^{-2} g/Mg (1.7×10^{-4} lb/ton) of clinker produced. This emission factor is based on the average of all test runs in Table C-2.

Calculations

Annual emissions:

$$67.5 \times 10^6 \text{ Mg} \times 8.7 \times 10^{-2} \text{ g/Mg} \times 0.96 = 5.6 \text{ Mg/yr} = 6.2 \text{ tons/yr}$$

Lime Manufacture

Basis of Input Data

1. Based on the total production of lime in 1989 and 1992 cited in the discussion of Lime Manufacturing (see p. 7-8), the estimated 1990 total production of lime was 15.6×10^6 Mg (17.2×10^6 tons)
2. An emission factor of 5.5×10^{-2} g/Mg of lime produced (1.1×10^{-4} lb/ton) is used. This figure is based on a study of mercury emissions from five kilns in Wisconsin and kiln production quantities cited on p. 7-13.¹⁰
3. Natural gas, which contains no mercury, is used to fire 33 percent of the lime kilns and thus would result in no mercury emissions from the fuel source.

Calculations

Annual emissions:

$$15.6 \times 10^6 \text{ Mg} \times 5.5 \times 10^{-2} \text{ g/Mg} \times 0.67 = 0.57 \text{ Mg/yr} = 0.63 \text{ tons/yr}$$

Carbon Black Production

Basis of Input Data

1. The 1990 total capacity for carbon black production was 1.47×10^6 Mg (1.62×10^6 tons).¹¹ No data were available for actual production of carbon black in 1990.
2. An emission factor of 1.5×10^{-4} kg of Hg/Mg of carbon black (3×10^{-4} lb/ton) is used.¹²
3. The emission factor is based only on the oil-furnace process which accounts for 99 percent of all carbon black production.

4. Mercury emissions are based on production capacity and not actual production. Use of actual production data would show a lower value for mercury emissions.

Calculations

$$\begin{aligned}\text{Annual emissions} &= 1.5 \times 10^{-4} \text{ kg/Mg} \times 1.47 \times 10^6 \text{ Mg} = \\ &0.22 \text{ Mg/yr} = 0.24 \text{ ton/yr}\end{aligned}$$

Byproduct Coke Production

No emission factors are available for mercury emissions from this process.

Primary Lead Smelting

Basis of Input Data

1. Based on background information in the NSPS for lead smelters, 100 units of ore yields 10 units of ore concentrate, 9 units of sinter, and 4.5 units of refined lead.¹³

ore	→	ore concentrate	→	sinter	→	refined lead
100 units		10 units		9 units		4.5 units
2. Using 1989 lead ore consumption levels with previous years data, the estimated 1990 lead ore utilization quantity was 3.74×10^6 Mg (4.11×10^6 tons).
3. The mercury emission factors from Table 7-5 for five emission sources in the process are:
 - a. materials handling: ore crushing = 0.0012 kg/Mg (0.0024 lb/ton) of raw material
 - b. materials handling: sinter charge mixing = 0.0065 kg/Mg (0.013 lb/ton) of ore concentrate
 - c. sinter machine leaks = 0.0007 kg/Mg (0.0014 lb/ton) of sinter
 - d. blast furnace = 0.0019 kg/Mg (0.0038 lb/ton) of ore concentrate
 - e. slag furnace + slag pouring = 0.0021 kg/Mg (0.0042 lb/ton) of lead product

Calculations

Annual emission from material handling (ore crushing):
 $0.0012 \text{ kg/Mg} * 3.74 \times 10^6 \text{ Mg} = 4.5 \text{ Mg/yr} = 5.0 \text{ tons/yr}$

Annual emission from material handling (sinter charge mixing): $0.0065 \text{ kg/Mg} * 3.74 \times 10^5 \text{ Mg} = 2.4 \text{ Mg/yr} = 2.6 \text{ tons/yr}$

Annual emissions from sintering:
 $0.0007 \text{ kg/Mg} * 3.36 \times 10^5 \text{ Mg} = 0.24 \text{ Mg/yr} = 0.26 \text{ tons/yr}$

Annual emission from blast furnace:
 $0.0019 \text{ kg/Mg} * 3.74 \times 10^5 \text{ Mg} = 0.71 \text{ Mg/yr} = 0.78 \text{ tons/yr}$

Annual emissions from slag furnace + slag pouring:
 $0.0021 \text{ kg/Mg} * 1.87 \times 10^5 \text{ Mg} = 0.39 \text{ Mg/yr} = 0.43 \text{ tons/yr}$

Total annual emissions:
 $4.5 \text{ Mg/yr} + 2.4 \text{ Mg/yr} + 0.24 \text{ Mg/yr} + 0.71 \text{ Mg/yr} + 0.39 \text{ Mg/yr}$
 $8.2 \text{ Mg/yr} = 9.0 \text{ tons/yr}$

Petroleum Refining

A mercury emission factor for the fluid caking unit in the conversion step was obtained from SPECIATE but the original references could not be obtained to confirm the emission data. Therefore, the data from SPECIATE were judged unacceptable for use. Mercury emission data were obtained from the CARB Air Toxics Emission Inventory Report for selected processes in petroleum refining using refinery gas as the fuel. No data could be located for the nationwide volume of refining gas used for these selected processes. Therefore, no mercury emissions could be calculated for the petroleum refining industry.

Oil Shale Retorting

Because there are no commercial oil shale retort facilities in operation in the U.S., a mercury emission value of zero has been assumed.

Geothermal Power Plants- -

Basis of Input Data

1. Only three States report production of electric power by geothermal means, California, Nevada, and Utah.
2. A mercury emission factor, based on a 1977 report, was stated to be 0.05 g/MW-hr from the cooling tower exhaust and 0.0073 g/MW-hr from the off-gas ejectors.¹⁴

3. It was assumed that the net capacity of the geothermal power plants stated in Table 7-8 was valid for 1990.
4. It was assumed that the mercury emission factors developed in 1977 for the California power facility are valid for all California, Nevada, and Utah facilities in 1990.
5. It was assumed that geothermal power plants operate 24 hr/d, 365 d/yr (8,760 hr/yr).

Calculations

Off-gas ejectors: $8,760 \text{ hr/yr} * 0.0073 \text{ g/MW-hr} *$
 $2,628.4 \text{ MW/yr} = 0.17 * 10^6 \text{ g/yr} = 0.17 \text{ Mg/yr}$

Cooling tower exhaust: $8,760 \text{ hr/yr} * 0.05 \text{ g/MW-hr} *$
 $2,628.4 \text{ MW/yr} = 1.15 * 10^6 \text{ g/yr} = 1.15 \text{ Mg/yr}$

Total annual emissions = $0.17 \text{ Mg/yr} + 1.15 \text{ Mg/yr} =$
 $1.3 \text{ Mg/yr} = 1.4 \text{ tons/yr}$

EMISSIONS FROM MISCELLANEOUS FUGITIVE AND AREA SOURCES

Mercury Catalysts

There is only one facility in the U.S. that may be using small quantities of mercury catalysts. Because no emission factors are available and only one facility, zero emissions have been assumed.

Dental Alloys

Basis for Input Data

1. In 1990, the total usage of mercury in dental equipment and supplies was 27 Mg (30 tons).²
2. It has been estimated that 2 percent of the mercury used in dental applications is emitted to the atmosphere.¹ This figure would correspond to an emission factor of 20 kg/Mg (40 lb/ton) of mercury used.
3. This emission factor is based on information approximately 15 years old so it should be viewed with caution because dental practices have changed considerably in the interim.

Calculation

Annual emissions = $20 \text{ kg/Mg} \times 27 \text{ Mg} = 0.54 \text{ Mg/yr} = 0.59 \text{ ton/yr}$

Mobile Sources

Basis for Input Data

1. An emission factor of $1.3 \times 10^{-3} \text{ mg/km}$ traveled ($4.6 \times 10^{-9} \text{ lb/mile}$) was obtained from a 1983 study.¹⁵
2. This emission factor should be interpreted with caution since it was based on a 1977 ambient sampling study, which was before the use of catalytic converters, unleaded gasoline, and state-regulated I/M programs.
3. In 1990, the total miles traveled in the U.S. was 2,147,501 million miles ($3,457,478 \times 10^6 \text{ km}$).¹⁶

Calculation

Annual emissions = $3.4575 \times 10^{12} \text{ km} \times 1.3 \times 10^{-3} \text{ mg/km} = 4.5 \times 10^9 \text{ mg} = 4.5 \text{ Mg/yr} = 5 \text{ tons/yr}$

Crematories

Basis for Input Data

1. In 1991, there were 400,500 crematories in the U.S.¹⁷
2. No data are available for the average quantity of mercury emitted for a cremation in the U.S. An estimated emission of 1 g of mercury per cremation has been recommended as a typical value in Europe.¹⁸ This emission factor will be used for estimations for the U.S.
3. There is a considerable variation in the overall dental care programs between the U.S. and Europe which may result in differences in the average number of mercury amalgam fillings per person.

Calculations

Annual emissions:

$400,500 \text{ cremations} \times 1 \text{ g/cremation} = 0.4 \text{ Mg/yr} = 0.44 \text{ ton/yr}$

Paint Application

Basis for Input Data

1. In 1990, the total usage of mercury in paints was 20 Mg (22 tons).²
2. It is estimated that 66 percent of the mercury used in paints is emitted into the atmosphere.¹⁹
3. This estimate presumes that all mercury emissions are generated from paint application in the year that the paint is produced.

Calculation

Annual emissions:

$$20 \text{ Mg} * 0.66 = 13.2 \text{ Mg} = 14.6 \text{ tons/yr}$$

TABLE A-1. SUMMARY OF MERCURY EMISSION FACTORS AND SCC

SCC number	Source description	Control status ^a	Mercury emission factor
3-03-999-99	Primary mercury production	C	0.13 kg/Mg produced
3-04-999-99	Secondary mercury production	U	20 kg/Mg produced
3-99-999-94	Battery manufacture (mercuric oxide)	U	1.0 kg/Mg used
1-01-001	Coal combustion: Utility boilers	U	7.6×10^{-15} kg/J produced
1-01-002	Coal combustion: Utility boilers	U	7.0×10^{-15} kg/J produced
1-02-001	Coal combustion: Industrial boilers	U	7.6×10^{-15} kg/J produced
1-02-002	Coal combustion: Industrial boilers	U	7.0×10^{-15} Mg/J produced
1-03-001	Coal combustion: Commercial & residential	U	7.6×10^{-15} kg/J produced
1-03-002	Coal combustion: Commercial & residential	U	7.0×10^{-15} kg/J produced
1-01-004	Oil combustion: Utility boilers	U	3.0×10^{-15} kg/J produced
1-01-005	Oil combustion: Utility boilers	U	2.9×10^{-15} kg/J produced
1-02-004	Oil combustion: Industrial boilers	U	3.0×10^{-15} kg/J produced
1-02-005	Oil combustion: Industrial boilers	U	2.9×10^{-15} kg/J produced
1-03-004	Oil combustion: Commercial & residential	U	3.0×10^{-15} kg/J produced
1-03-005	Oil combustion: Commercial & residential	U	2.9×10^{-15} kg/J produced
1-02-009	Wood combustion: Boilers	U	3.4×10^{-6} kg/Mg burned
5-01-001-02	Municipal waste combustors: Mass burn	U	2.8 g/Mg waste
5-01-001-02	Municipal waste combustors: Mass burn	C	1.4 g/Mg waste
5-01-001-03	Municipal waste combustors: RDF	C	1.4 g/Mg waste
5-01-001	Municipal waste combustors: Modular	U	2.8 g/Mg waste
5-01-005-15	Sewage sludge incinerators	C	0.018 g/Mg sludge
5-01-005-16	Sewage sludge incinerators	U	5.0 g/Mg sludge
5-01-005-16	Sewage sludge incinerators	C	1.6 g/Mg sludge

TABLE A-1. (continued)

SCC number	Source description	Control status ^a	Mercury emission factor
5-01-005-05	Medical waste incinerators: mixed waste	U	20 g/Mg burned
5-01-005-05	Medical waste incinerators: red bag	U	16 g/Mg burned
5-01-005-05	Medical waste incinerators: Pathological waste	U	0.5 g/Mg burned
3-05-006-06	Portland cement production: Dry process	C	8.7×10^{-2} g/Mg produced
3-05-007-06	Portland cement production: Wet process	C	8.7×10^{-2} g/Mg produced
3-05-016-04	Lime manufacture: rotary kiln	C	5.5×10^{-2} g/Mg produced
3-01-005-04	Carbon black production: Oil furnace	C	1.5×10^{-4} kg/Mg produced
3-03-010-02	Primary lead smelting: Blast furnace	C	1.9×10^{-3} kg/Mg ore concentrate
3-03-010-08	Primary lead smelting: Slag fume furnace (including slag pouring)	C	2.1×10^{-3} kg/Mg lead
3-03-010-04	Primary lead smelting: ore crushing	U	1.2×10^{-3} kg/Mg raw material
3-03-010-15	Primary lead smelting: Sinter crushing	U	6.5×10^{-3} kg/Mg ore
3-03-010-25	Primary lead smelting: Sinter leakage	U	7×10^{-4} kg/Mg sinter
1-01-015-01	Geothermal power plant: Off-gas ejectors	U	7.3×10^{-3} g/MW-hr produced
1-01-015-02	Geothermal power plant: Cooling tower	U	0.05 g/MW-hr produced
3-15-021-01	Crematories	U	1.0 g/human body

^aU = uncontrolled; C = controlled.

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APPENDIX B

SUMMARY OF COMBUSTION SOURCE MERCURY EMISSION DATA

TABLE B-1. SUMMARY OF COAL COMBUSTION EMISSION DATA

Industry sector ^a	Facility type ^b	Control status ^c	Coal type ^d	Emission factor ^e			
				kg/10 ¹⁵ J		lb/10 ¹² Btu	
				Mean	Range	Mean	Range
U	PC/DB	ESP	B	4.7	--	11	--
U	PC/DB	WS	B	bd	--	bd	--
U	PC/DB	MP/ESP	B	9.5	--	22	--
U	PC/DB	MP/ESP	B	9.6	--	22	--
U	PC/DB	MP/ESP	B	2.5	1.5-3.5	5.9	3.6-8.2
U	PC/DB	ESP	B	2.5	0.56-4.2	5.8	1.3-9.7
U	PC/DB	UN	B	31	4.9-130	72	11-310
U	PC/DB	UN	B	9.9	--	23	--
U	PC/DB	ESP	B	7.7	--	18	--
U	PC/DB	UN	B	4.3	--	10	--
U	PC/DB	UN	B	1.7	--	3.9	--
U	PC/DB	UN	B	6.9	--	16	--
U	PC/DB	ESP	B	0.65	--	1.5	--
U	PC/DB	ESP	B	1.1	--	2.6	--
U	PC/DB	ESP	B	0.86	--	2.0	--
U	PC/DB	ESP	B	1.3	--	3.1	--
U	PC/DB	MP	B	3.7	1.6-9.1	8.5	3.7-21
U	PC/DB	MP/ESP	B	0.32	0.18-0.86	0.75	0.41-2.0
U	PC/DB	MP/ESP	B	0.086	<0.0047-0.24	0.20	<0.011-0.56
U	PC/WB	MP/ESP	B	2.3	--	5.3	--
U	PC/WB	ESP	B	1.1	--	2.6	--
U	PC/WB	ESP	B	1.8	--	4.2	--
U	PC/WB	VS	B	0.069	--	0.16	--
U	PC/WB	ESP	B	2.2	--	5.1	--
U	PC/WB	ESP	B	2.7	--	6.3	--

TABLE B-1. (continued)

Industry sector ^a	Facility type ^b	Control status ^c	Coal type ^d	Emission factor ^e			
				kg/10 ¹⁵ J		lb/10 ¹² Btu	
				Mean	Range	Mean	Range
U	CY	WS	B	2.1	--	4.9	--
U	CY	ESP	B	1.7	--	4.0	--
U	CY	ESP	B	2.2	--	5.1	--
U	CY	ESP	B	4.1	--	9.5	--
U	CY	ESP	B	7.6	--	18	--
U	CY	ESP	B	4.3	--	10	--
U	CY	ESP	B	2.6	--	6.1	--
U	S	FF	B	2.0	--	4.6	--
U	S	MP	B	11	--	26	--
U	S	MC	B	1.1	--	2.5	--
U	CY	UN	SB	35	--	81	--
U	CY	WS	SB	2.1	--	4.9	--
U	PC	VS	SB	4.7	--	11	--
U	PC	ESP	SB	1.8	--	4.1	--
U	NA	ESP	SB	0.86	--	2.0	--
U	NA	ESP	SB	0.73	--	1.7	--
U	PC/DB	MC	L	1.9	--	4.4	--
U	PC/DB	MC	L	2.8	--	6.5	--
U	PC/DB	ESP	L	<0.099	--	<0.23	--
U	CY	ESP	L	.020	--	0.46	--
U	CY	CY	L	9.5	--	22	--
U	SS	MC	L	2.4	--	5.6	--
U	SS	ESP	L	0.23	--	0.53	--
I	PC/DB	ESP	B	1.8	--	4.2	--
I	PC/DB	ESP	B	1.9	--	4.4	--

TABLE B-1. (continued)

Industry sector ^a	Facility type ^b	Control status ^c	Coal type ^d	Emission factor ^e			
				kg/10 ¹⁵ J		lb/10 ¹² Btu	
				Mean	Range	Mean	Range
I	PC/DB	MC	B	77	--	180	--
I	PC/DB	MC/WS	B	37	--	86	--
I	PC/WB	MC	B	2.9	--	6.7	--
I	SS	MC/ESP	B	1.8	--	4.2	--
I	SS	MC	B	2.5	--	5.8	--
I	SS	MC	B	11	--	25	--
I	SS	UN	B	0.33	0.33-0.34	0.77	0.76-0.78
I	SS	UN	B	1.7	1.1-2.2	3.9	2.5-5.1
I	SS	UN	B	0.99	--	2.3	--
I	SS	UN	B	0.69	0.56-0.86	1.6	1.3-2.0
I	SS	UN	B	1.4	1.1-1.7	3.2	2.5-3.9
I	SS	UN	B	1.7	0.69-2.8	4.0	1.6-6.5
I	OS	UN	B	0.047	--	0.11	--
I	OS	UN	B	0.73	--	1.7	--
I	OS	UN	B	0.56	0.32-0.82	1.3	0.74-1.9
I	OS	UN	B	0.90	--	2.1	--
I	OS	MP	B	0.34	0.17-0.52	0.80	0.39-1.2
I	SS	UN	B	1.8	--	4.1	--
I	SS	MP/ESP	B	1.0	--	2.4	--
I	SS	UN	B	5.2	--	12	--
I	SS	MP/ESP	B	0.43	--	1.0	--
I	SS	UN	SB	3.8	0.37-7.3	8.9	0.86-17
I	SS	UN	SB	0.28	--	0.64	--
I	SS	MP/ESP	SB	0.28	--	0.64	--
I	SS	UN	SB	0.39	--	0.91	--

TABLE B-1. (continued)

Industry sector ^a	Facility type ^b	Control status ^c	Coal type ^d	Emission factor ^e			
				kg/10 ¹⁵ J		lb/10 ¹² Btu	
				Mean	Range	Mean	Range
I	SS	MP/ESP	SB	0.16	--	0.37	--
C	PC/DB	UN	B	2.5	--	5.8	--
C	PC/DB	MC/WS	B	0.47	--	1.1	--
C	US	UN	B	0.18	--	0.42	--
C	SS	MP	B	0.60	--	1.4	--
C	OS	MP	B	5.6	--	13	--
C	S	UN	A	3.0	--	7.0	--
C	S	UN	A	1.5	--	3.5	--
C	S	UN	A	2.3	--	5.3	--
R	--	UN	B	3.3	--	7.7	--
R	--	UN	B	10	--	23	--
R	--	UN	B	11	--	27	--
R	--	UN	B	<0.39	--	<0.9	--

^aU = utility, I = industrial, C = commercial, R = residential

^bPC = pulverized coal, DB = dry bottom, WB = wet bottom, CY = cyclone, NA = not available, SS = spreader stoker, OS = overfeed stoker, US = underfeed stoker, S = stoker

^cESP = electrostatic precipitator, WS = wet scrubber, MP = mechanical precipitation device, UN = uncontrolled, VS = venturi scrubber, FF = fabric filter, MC = multiclone, CY = cyclone

^dB = bituminous, SB = subbituminous, L = lignite, A = anthracite

^ebd = below detection limit

TABLE B-2. SUMMARY OF MUNICIPAL WASTE COMBUSTOR EMISSION DATA

Facility name	Combustor type ^a	Control technology ^b	Concentration $\mu\text{g/dscm}$ @ 7% O_2
Adirondack (Boiler A)	MB/WW	U	328
Adirondack (Boiler B)	MB/WW	U	659
Adirondack (Boiler B)	MB/WW	U	439
Adirondack average	MB/WW	U	475
Camden (Unit 1)	MB/WW	U	710
Commerce	MB/WW	UN	450
Commerce	MB/WW	UN	453
Commerce	MB/WW	UN	261
Commerce average	MB/WW	UN	388
Quebec City - Pilot	MB/WW	UN	445
Quebec City - Pilot	MB/WW	UN	360
Quebec City - Pilot	MB/WW	UN	451
Quebec City - Pilot	MB/WW	UN	320
Quebec City - Pilot	MB/WW	UN	480
Quebec City - Pilot	MB/WW	UN	187
Quebec City average	MB/WW	UN	374
Vancouver (11/88)	MB/WW	UN	527
Vancouver (3/89)	MB/WW	UN	1,200
Vancouver (4/89)	MB/WW	UN	1,360
Vancouver (8/89)	MB/WW	UN	661
Vancouver average	MB/WW	UN	937
Babyion	MB/WW	SD/FF	323
Bristol	MB/WW	SD/FF	99.0
Bristol	MB/WW	SD/FF	10
Bristol	MB/WW	SD/FF	64.0
Bristol	MB/WW	SD/FF	399
Bristol average	MB/WW	SD/FF	167
Commerce (1987)	MB/WW	SD/FF	570
Commerce (1988)	MB/WW	SD/FF	68.0
Commerce (1988)	MB/WW	SD/FF	39.0
Commerce average	MB/WW	SD/FF	226
Fairfax	MB/WW	SD/FF	331
Fairfax	MB/WW	SD/FF	406
Fairfax	MB/WW	SD/FF	466
Fairfax	MB/WW	SD/FF	514
Fairfax average	MB/WW	SD/FF	429

TABLE B-2. (continued)

Facility name	Combustor type ^a	Control technology ^b	Concentration $\mu\text{g/dscm}$ @ 7% O ₂
Hempstead, Unit 1(9/89)	MB/WW	SD/FF	9.28
Hempstead, Unit 2(9/89)	MB/WW	SD/FF	25.5
Hempstead, Unit 3(10/89)	MB/WW	SD/FF	25.0
Hempstead average	MB/WW	SD/FF	19.9
Huntsville	MB/WW	SD/FF	463
Huntsville	MB/WW	SD/FF	1,280
Huntsville average	MB/WW	SD/FF	869
Indianapolis	MB/WW	SD/FF	200
Indianapolis	MB/WW	SD/FF	277
Indianapolis, Unit 1	MB/WW	SD/FF	283
Indianapolis average	MB/WW	SD/FF	253
Kent	MB/WW	SD/FF	166
Kent	MB/WW	SD/FF	248
Kent average	MB/WW	SD/FF	207
Long Beach	MB/WW	SD/FF	180
Marion County	MB/WW	SD/FF	239
Stanislaus County	MB/WW	SD/FF	427
Stanislaus County	MB/WW	SD/FF	508
Stanislaus County	MB/WW	SD/FF	481
Stanislaus County, Unit 1	MB/WW	SD/FF	499
Stanislaus County, Unit 2	MB/WW	SD/FF	462
Stanislaus County average	MB/WW	SD/FF	475
Adirondack (Boiler A)	MB/WW	SD/ESP	574
Adirondack (Boiler B)	MB/WW	SD/ESP	74.8
Adirondack (Boiler B)	MB/WW	SD/ESP	131
Adirondack average	MB/WW	SD/ESP	87.7
Camden (Unit 1)	MB/WW	SD/ESP	217
Charleston (Units A & B)	MB/WW	SD/ESP	723
Charleston (Unit A)	MB/WW	SD/ESP	457
Charleston (Unit B)	MB/WW	SD/ESP	498
Charleston average	MB/WW	SD/ESP	559
Haverill, Unit A (6/89)	MB/WW	SD/ESP	247
Haverill, Unit B (3/90)	MB/WW	SD/ESP	567
Haverill, Unit B (6/89)	MB/WW	SD/ESP	208
Haverill average	MB/WW	SD/ESP	341

TABLE B-2. (continued)

Facility name	Combustor type ^a	Control technology ^b	Concentration $\mu\text{g/dscm}$ @ 7% O ₂
Millbury, Unit 1	MB/WW	SD/ESP	565
Millbury, Unit 2	MB/WW	SD/ESP	954
Millbury average	MB/WW	SD/ESP	760
Portland, Unit 1 (12/89)	MB/WW	SD/ESP	550
Portland, Unit 2 (12/89)	MB/WW	SD/ESP	382
Portland average	MB/WW	SD/ESP	466
Hillsborough	MB/WW	ESP	823
Pinellas County	MB/WW	ESP	847
Quebec City	MB/WW	ESP	685
Tulsa	MB/WW	ESP	746
Tulsa	MB/WW	ESP	466
Tulsa	MB/WW	ESP	711
Tulsa	MB/WW	ESP	600
Tulsa	MB/WW	ESP	418
Tulsa	MB/WW	ESP	1,000
Tulsa	MB/WW	ESP	97.0
Tulsa average	MB/WW	ESP	577
Vancouver (12/89)	MB/WW	DSI/FF	156
Vancouver (12/89)	MB/WW	DSI/FF	117
Vancouver (12/89)	MB/WW	DSI/FF	127
Vancouver (3/89)	MB/WW	DSI/FF	456
Vancouver (4/89)	MB/WW	DSI/FF	632
Vancouver (8/89)	MB/WW	DSI/FF	95.0
Vancouver, Unit 1 (9/89)	MB/WW	DSI/FF	470
Vancouver, Unit 2 (9/89)	MB/WW	DSI/FF	368
Vancouver, Unit 3 (11/88)	MB/WW	DSI/FF	485
Vancouver, Unit 3 (9/89)	MB/WW	DSI/FF	1,080
Vancouver, Unit 3 (9/89)	MB/WW	DSI/FF	1,090
Vancouver average	MB/WW	DSI/FF	461
Delaware (Unit 1)	MB/RC	SD/FF	40.6
Delaware (Unit 2)	MB/RC	SD/FF	22.6
Delaware (Unit 3)	MB/RC	SD/FF	30.5
Delaware (Unit 4)	MB/RC	SD/FF	27.3
Delaware (Unit 5)	MB/RC	SD/FF	54.3
Delaware (Unit 6)	MB/RC	SD/FF	84.1

TABLE B-2. (continued)

Facility name	Combustor type ^a	Control technology ^b	Concentration $\mu\text{g/dscm}$ @ 7% O_2
Delaware (Unit 1)	MB/RC	SD/FF	30.1
Delaware (Unit 2)	MB/RC	SD/FF	50.2
Delaware (Unit 3)	MB/RC	SD/FF	57.6
Delaware (Unit 4)	MB/RC	SD/FF	87.0
Delaware (Unit 5)	MB/RC	SD/FF	41.0
Delaware (Unit 6)	MB/RC	SD/FF	42.8
Delaware average	MB/RC	SD/FF	47.4
York (Unit 1)	MB/RC	SD/FF	158
York (Unit 2)	MB/RC	SD/FF	105
York (Unit 3)	MB/RC	SD/FF	79.3
York (Unit 1)	MB/RC	SD/FF	151
York (Unit 2)	MB/RC	SD/FF	167
York (Unit 3)	MB/RC	SD/FF	136
York (Unit 1)	MB/RC	SD/FF	155
York (Unit 2)	MB/RC	SD/FF	167
York (Unit 3)	MB/RC	SD/FF	136
York (Unit 1)	MB/RC	SD/FF	36.1
York (Unit 2)	MB/RC	SD/FF	53.0
York (Unit 3)	MB/RC	SD/FF	120
York (Unit 1)	MB/RC	SD/FF	48.4
York (Unit 1)	MB/RC	SD/FF	54.0
York (Unit 2)	MB/RC	SD/FF	55.4
York (Unit 3)	MB/RC	SD/FF	40.1
York (Unit 1)	MB/RC	SD/FF	153
York (Unit 2)	MB/RC	SD/FF	79.2
York (Unit 3)	MB/RC	SD/FF	150
York average	MB/RC	SD/FF	110
AVERAGE	MB/RC	SD/FF	70.6
Dayton	MB/REF	UN	716
Dayton	MB/REF	UN	907
Dayton	MB/REF	UN	962
Dayton	MB/REF	UN	973
Dayton	MB/REF	UN	1,060
Average	MB/REF	UN	923

TABLE B-2. (continued)

Facility name	Combustor type ^a	Control technology ^b	Concentration $\mu\text{g}/\text{dscm}$ @ 7% O_2
Dayton	MB/REF	ESP	1,020
Dayton	MB/REF	ESP	1,150
Average	MB/REF	ESP	1,080
Dayton	MB/REF	DSI/ESP	491
Biddeford	RDF	UN	389
Mid-Connecticut (2/89)	RDF	UN	668
Mid-Connecticut (7/88)	RDF	UN	1,010
Mid-Connecticut (7/88)	RDF	UN	884
Mid-Connecticut Average	RDF	UN	853
Mid-Connecticut (2/89)	RDF	SD/FF	9.20
Mid-Connecticut (7/88)	RDF	SD/FF	50.0
Mid-Connecticut Average	RDF	SD/FF	29.6
Honolulu, Unit 1	RDF	SD/ESP	5.28
Honolulu, Unit 2	RDF	SD/ESP	7.25
Average	RDF	SD/ESP	6.27
Semass, Unit 1	RDF	SD/ESP	59.3
Semass, Unit 2	RDF	SD/ESP	105
Average	RDF	SD/ESP	82.2
West Palm Beach, Unit 1	RDF	SD/ESP	55.6
West Palm Beach, Unit 2	RDF	SD/ESP	23.2
Average	RDF	SD/ESP	39.4
Detroit (3/90)	RDF	ESP	194
Detroit (7/89)	RDF	ESP	653
Average	RDF	ESP	424
Albany	RDF	ESP	441
Pigeon Point	MOD/EA	ESP	363
Pope/Douglas	MOD/EA	ESP	133
Dyersburg	MOD/SA	UN	130
Oneida County	MOD/SA	ESP	2,060

^aMB = mass burn, WW = water wall, REF = refractory wall, RDF = refuse-derived fuel-fired, MOD = modular, SA = starved air, EA = excess air.

^bUN = uncontrolled, SD = spray dryer, FF = fabric filter, ESP = electrostatic precipitator, DSI = duct sorbent injection.

TABLE B-3. SUMMARY OF SEWAGE SLUDGE INCINERATOR EMISSION DATA

Incinerator type ^a	Control status ^b	Method ^c	Emission factor		Ref.
			g/Mg dry sludge	10 ⁻³ lb/ton dry sludge	
MH	IS	T	0.35	0.70	51
FB	SC	T	24	48	51
MH	IS	T	0.90	1.8	51
NA	NA	T	1.5	3.0	51
FB	VS/IS	T	1.6 - 3.1	3.2 - 6.2	51
FB	VS/IS	NA	0.026	0.051	14
MH	NA	T	0.83 - 14	1.7 - 27	14
MH	VS/IS	T	1.1	2.1	14
MH	NA	NA	3.0	6.0	14
MH	UN	MB	0.54 - 0.84	1.1 - 1.7	14
MH	UN	MB	0.66	1.3	14
MH	UN	MB	4.6	9.2	14
MH	UN	MB	3.4 - 4.0	6.8 - 8.0	14
MH	UN	MB	1.2 - 2.1	2.4 - 4.2	14
NA	UN	MB	0.32	0.64	14
MH	UN	MB	0.58	1.2	14
MH	IS	T	0.97	1.9	49
FB	VS/IS	T	0.030	0.060	49

^aMH = multiple hearth, FB = fluidized-bed, NA = not available.

^bIS = impingement scrubber, SC = spray chamber, NA = not available, VS = venturi scrubber, UN = uncontrolled.

^cT = source test, NA = not available, MB = mass balance.

TABLE B-4. SUMMARY OF MEDICAL WASTE INCINERATOR EMISSION DATA

Facility	Waste type ^a	Control status ^b	No. of runs	Emission factor			
				g/Mg of waste		10 ⁻³ lb/ton of waste	
				Average	Range	Average	Range
Fox Chase	M	VS/PB	3	0.72	--	1.44	--
Southland	M	DSI/ESP	3	9.0	2.73-16.7	18.0	5.46-33.4
Royal Jubilee ^c	M	UN	2	0.0129	0.0124-0.0134	0.0259	0.0248-0.0269
Mega	NA	VS/PB	3	3.22	2.08-4.24	6.45	4.17-9.49
Nazareth	M	VS/PB	2	14	8.1-2.0	28	16-40
St. Bernadines	M	UN	3	9.7	8.4-12.2	19.4	16.8-24.5
Kaiser	M	WS	3	15.8	0.41-33.4	31.7	0.82-66.8
USC	M	UN	3	317	9.92-914	634	19.8-1, 830
Borgess	G500	UN	14	66.2	20.3-165	132	40.6-329
		DI/FF	9	50.0	19.5-109	100	39.0-218
		DI/FF + C ^d	2	5.84	5.25-6.42	11.7	10.5-12.8
		DI/FF + C ^e	3	2.48	0.739-4.18	4.97	1.48-8.36
	RB	UN	10	16.2	0.922-630	32.3	1.84-126
		DI/FF	9	26.2	2.61-84.2	52.4	5.22-168
	G100	UN	2	1.13	0.240-2.01	2.25	0.480-4.02
University of Michigan	M	UN	3	4.03	1.98-5.35	8.06	3.95-10.7
		VS/PB	3	3.66	0.74-7.26	7.33	1.49-14.5
Lenoir	M	UN	9	7.15	1.05-510	14.3	2.10-1,020
Cape Fear	M	UN	9	11.6	0.58-560	23.3	1.16-1,120
AMI Central Carolina	M	UN	3	0.043	<0.00055-0.081	0.086	<0.0011-0.162
	P	UN	6	0.5	<0.0005-1.5	1.0	<0.0010-3.0
Morristown	M	UN	6	37.1	8.11-65.4	74.3	16.2-131
		SD/FF	3	23.9	8.29-49.2	47.8	16.6-98.4
		SD/FF + C	3	3.98	1.51-6.12	7.96	3.02-12.2

^aM = mixed medical waste, NA = not available, G500 = mixed waste from 500-bed hospital, RB = red bag waste, G100 = mixed waste from 100-bed hospital, P = pathological waste.

^bVS = venturi scrubber, PB = packed bed, DSI = duct sorbent injection, ESP = electrostatic precipitator, UN = uncontrolled, WS = wet scrubber, DI = dry injection, FF = fabric filter, C = carbon addition, SD = spray dryer.

^cSampling method suspect, results biased low.

^dCarbon injection at 1 lb/hr rate.

^eCarbon injection at 2.5 lb/hr rate.

APPENDIX C.

SELECTED INFORMATION FOR CEMENT KILNS AND LIME PLANTS

- C.1 - UNITED STATES PORTLAND CEMENT
KILN CAPACITIES--1990
- C.2 - SUMMARY OF PORTLAND CEMENT
EMISSION FACTORS
- C.3 - LIME PLANTS IN THE UNITED STATES
IN 1991

TABLE C-1. PORTLAND CEMENT PRODUCTION FACILITIES

Company and location	No./type of kiln	Clinker capacity, ^a 10 ³ tons/year
Alamo Cement Co. San Antonio, TX	1 - Dry	750
Allentown Cement Co., Inc. Blandon, PA	2 - Dry	930
Armstrong Cement & Sup. Co. Cabot, PA	2 - Wet	310
Ash Grove Cement Co. Nephi, UT	1 - Dry	600
Louisville, NE	2 - Dry	961
Durkee, OR	1 - Dry	500
Foreman, AR	3 - Wet	945
Montana City, MT	1 - Wet	280
Chanute, KS	2 - Wet	496
Inkom, ID	2 - Wet	210
Blue Circle Inc. Ravena, NY	2 - Wet	1,532
Atlanta, GA	2 - Dry	612
Tulsa, OK	2 - Dry	600
Calera, AL	2 - Dry	600
Boxcrow Cement Midlothian, TX	1 - Dry	1,000
Calaveras Cement Co. Redding, CA	1 - Dry	651
Tehachapi, CA	1 - Wet	425
California Portland Cement Mojave, CA	1 - Dry	1,039
Colton, CA	2 - Dry	750
Rillito, AZ	4 - Dry	1,065
Capitol Cement Corporation Martinsburg, WV	3 - Wet	822
Capitol Aggregates, Inc. San Antonio, TX	1-Dry/1-Wet	503/352
Carlow Group Zanesville, OH	2 - Wet	603
Centex Laramie, WY	1 - Dry	461
La Salle, IL	1 - Dry	410
Fernley, NV	2 - Dry	415
Continental Cement Co., Inc. Hannibal, MO	1 - Wet	600
Dixon-Marquette Dixon, IL	4 - Dry	524
Dragon Products Company Thomaston, ME	1 - Wet	455
Essroc Materials Nazareth, PA	1 - Dry	963
Speed, IN	2 - Dry	951
Bessemer, PA	1-Dry/1-Wet	325/211
Frederick, MD	2 - Wet	370
Logansport, IN	2 - Wet	404

TABLE C-1. (continued)

Company and location	No./type of kiln	Clinker capacity, ^a 10 ³ tons/year
Florida Crushed Stone Brooksville, FL	1 - Dry	571
Giant Cement Company Harleyville, SC	4 - Wet	870
Gifford-Hill & Co., Inc. Harleyville, SC	1 - Dry	617
Oro Grande, CA	7 - Dry	1,148
Riverside, CA	2 - Dry	110
Glens Falls Cement Co. Glens Falls, NY	1 - Dry	495
Hawaiian Cement Company Ewa Beach, HI	1 - Dry	263
Heartland Cement Company Independence, KS	4 - Dry	336
Hercules Cement Company Stockertown, PA	3 - Dry	723
Holnam, Inc. Theodore, AL	1 - Dry	1,442
Clarkeville, MO	1 - Wet	1,312
Holly Hill, SC	2 - Wet	1,092
Mason City, IA	2 - Dry	888
Florence, CO	3 - Wet	860
Fort Collins, CO	1 - Dry	494
Dundee, MI	2 - Wet	970
Artesia, MS	1 - Wet	504
Seattle, WA	1 - Wet	473
Three Forks, MT	1 - Wet	312
Ada, OK	2 - Wet	600
Tijeras, NM	2 - Dry	494
Saratoga, AR	2 - Wet	369
Morgan, UT	2 - Wet	328
Independent Cement Corp. Catskill, NY	1 - Wet	512
Hagerstown, MD	1 - Dry	498
Kaiser Cement Corp. Permanente, CA	1 - Dry	1,600
Keystone Cement Company Bath, PA	2 - Wet	602
Kosmos Cement Co. Louisville, KY	1 - Dry	724
Pittsburgh, PA	1 - Wet	394
LaFarge Corporation New Braunfels, TX	1 - Dry	954
Buffalo, IA	1 - Dry	858
Demopolis, AL	1 - Dry	722
Grand Chain, IL	2 - Dry	1,186
Alpena, MI	5 - Dry	1,954
Whitehall, PA	3 - Dry	760
Sugar Creek, MO	2 - Dry	482
Paulding, OH	2 - Wet	490
Fredonia, KS	2 - Wet	382

TABLE C-1. (continued)

Company and location	No./type of kiln	Clinker capacity, ^a 10 ³ tons/year
Lehigh Portland Cement		
Mason City, IA	1 - Dry	760
Leeds, AL	1 - Dry	651
Cementon, NY	1 - Wet	558
Union Bridge, MD	4 - Dry	992
Mitchell, IN	3 - Dry	760
York, PA	1 - Wet	99
Waco, TX	1 - Wet	81
Lone Star Industries		
Cape Girardeau, MO	1 - Dry	1,104
Greencastle, IN	1 - Wet	715
Oglesby, IL	1 - Dry	465
Pryor, OK	3 - Dry	687
Nazareth, PA	4 - Dry	623
Sweetwater, TX	3 - Dry	495
Medusa Cement Co.		
Charlevoix, MI	1 - Dry	1,364
Clinchfield, GA	1-Dry/1-Wet	560/206
Wampum, PA	3 - Dry	703
Mitsubishi Cement Corp.		
Lucerne Valley, CA	1 - Dry	1,669
Monarch Cement Company		
Humboldt, KS	3 - Dry	674
Des Moines, IA	2 - Wet	300
National Cement Company		
Ragland, AL	1 - Dry	845
Natl. Cement Co. of California		
Lebec, CA	1 - Dry	650
North Texas Cement		
Midlothian, TX	3 - Wet	900
Phoenix Cement Company		
Clarkdale, AZ	3 - Dry	705
Rinker Portland Cement Corp.		
Miami, FL	2 - Wet	564
River Cement Company		
Festus, MO	2 - Dry	1,179
RMC Lonestar		
Davenport, CA	1 - Dry	800
Roanoke Cement Company		
Cloverdale, VA	5 - Dry	1,117
Signal Mountain Cement Co.		
Chattanooga, TN	2 - Wet	450
South Dakota Cement		
Rapid City, SD	1-Dry/2-Wet	450/316
Southdown, Inc.		
Victorville, CA	2 - Dry	1,550
Brooksville, FL	2 - Dry	1,200
Knoxville, TN	1 - Dry	600
Fairborn, OH	1 - Dry	610
Lyons, CO	1 - Dry	450
Odessa, TX	2 - Dry	550

TABLE C-1. (continued)

Company and location	No./type of kiln	Clinker capacity, ^a 10 ³ tons/year
St. Mary's Peerless Cement Co. Detroit, MI	1 - Wet	610
Tarmac Florida, Inc. Medley, FL	3 - Wet	1,028
Texas Industries New Braunfels, TX Midlothian, TX	1 - Dry 4 - Wet	759 1,256
Texas-Lehigh Cement Co. Buda, TX	1 - Dry	987
Total capacity reported	135 - Dry/79 - Wet	81,056

Source: U.S. and Canadian Portland Cement Industry: Plant Information Summary. December 31, 1990. Portland Cement Association, Skokie, Illinois. July 1991.

^aNote:

Kilns reported as inactive in 1990

			Clinker capacity, 10 ³ tons/yr
Ash Grove Cement	Foreman, AR	1 kiln	271
California Portland Cement	Rillito, AZ	2 kilns	270
Holnam, Inc.	Florence, CO	2 kilns	368
Lone Star Industries	Sweetwater, TX	1 kiln	165
Medusa Cement Company	Clinchfield, GA	1 kiln	206
Monarch Cement Company	Des Moines, IA	2 kilns	300
Tarmac Florida	Medby, FL	2 kilns	368
Total active capacity			79,108

TABLE C-2. SUMMARY OF MERCURY EMISSION FACTORS FOR PORTLAND CEMENT PRODUCTION

Facility	Facility location	Control status ^a	No. of runs	Average clinker production rate Mg/hr (tons/hr)	Emission factor			
					10 ⁻³ kg/Mg of clinker		10 ⁻³ lb/ton of clinker	
					Average	Range	Average	Range
Lone Star Industries	Cape Girardeau, MO	BH	3	149 (164) Phase 1 test	0.01	0.0088 - 0.013	0.020	0.0176 - 0.0252
Lone Star Industries	Cape Girardeau, MO	BH	3	145 (160) Phase 2 test	0.22	0.113 - 0.4	0.43	0.225 - 0.8
LaFarge Corp.	Demopolis, AL	ESP (2)	3	102 (112)	0.08	0.067 - 0.090	0.16	0.134 - 0.179
Ash Grove Cement Co.	Foreman, AR	ESP	6	45 (49) Kiln No. 3	0.02	0.011 - 0.028	0.035	0.022 - 0.055
Ash Grove Cement Co.	Foreman, AR	ESP	4	32 (35) Kiln No. 1	0.04	0.022 - 0.055	0.07	0.043 - 0.11
Ash Grove Cement Co.	Chanute, KS	ESP	4	30 (33) Kiln No. 1	0.49	0.14 - 1.25	0.97	0.28 - 2.5
Ash Grove Cement Co.	Chanute, KS	ESP	4	30 (33) Kiln No. 2	0.08	0.033 - 0.15	0.15	0.066 - 0.29
Ash Grove Cement Co.	Louisville, NE	ESP	3	40 (44) Kiln No. 1	0.047	0.03 - 0.087	0.095	0.05 - 0.123
Ash Grove Cement Co.	Louisville, NE	ESP (2)	4	57 (63) Kiln No. 2	0.015	0.01 - 0.030	0.030	0.019 - 0.059
Essroc Materials	Frederick, MD	NS	3	43 (47) Test No. 1	0.11	0.075 - 0.13	0.22	0.15 - 0.26
Essroc Materials	Frederick, MD	NS	3	44 (48) Test No. 2	0.11	0.075 - 0.14	0.22	0.15 - 0.27
LaFarge Corp.	Paulding, OH	ESP	3	55 (61)	0.016	0.014 - 0.018	0.032	0.028 - 0.036
Lone Star Industries	Oglesby, IL	ESP	2	54 (59) Test No. 1	0.0023	0.0016 - 0.0030	0.0045	0.0032 - 0.0059
Lone Star Industries	Oglesby, IL	ESP	3	54 (60) Test No. 2	0.014	0.008 - 0.020	0.028	0.012 - 0.040
Holnam Inc.	Clarkeville, MO	ESP	3	163 (180)	0.049	0.036 - 0.06	0.097	0.072 - 0.12

^aBH = baghouse

ESP = electrostatic precipitator

NS = not stated

TABLE C-3. LIME PLANTS ACTIVE IN THE UNITED STATES IN 1991^a
(Source: National Lime Association)

Company/headquarters location	Plant location/name	Type of lime produced
<u>Alabama</u>		
Allied Lime Company (HQ) Birmingham, AL	Alabaster	Q
Blue Circle, Inc. Calera, AL	Montevallo	Q, H
Cheney Lime & Cement Company Allgood, AL	Roberts	Q, H
Dravo Lime Company Saginaw, AL	Landmark Allgood ^b	Q, H H
	Longview Div.	Q, H
<u>Arizona</u>		
Chemstar Lime, Inc. (HQ) Phoenix, AZ	Douglas Nelson	Q Q, H
Magma Cooper Company (C) San Manuel, AZ	San Manuel	H
<u>Arkansas</u>		
Arkansas Lime Company Batesville, AR	Batesville	Q, H
<u>California</u>		
Spreckles Sugar Company, Inc. (C) Woodland, CA	Woodland	Q
Chemstar Lime, Inc. (HQ) Phoenix, AZ	City of Industry ^b Stockton ^b	H H
Delta Sugar Corp. (C) Clarksburg, CA	Clarksburg	H
Holly Sugar Corp. (C) Colorado Springs, CO	Hamilton City Brawley Tracy	Q Q Q
Marine Magnesium Company (C) S. San Francisco, CA	Sonora	Q
National Refractories & Minerals Corp. Moss Landing, CA	Natividad	DL
Union Sugar Division of Holly Sugar Corp. (C) Santa Maria, CA	Betteravia	Q
<u>Colorado</u>		
Calco, Inc. Salida, CO	Salida	Q
Western Sugar Company Fort Morgan, CO	Fort Morgan	Q
Greeley, CO	Greeley	Q
<u>Idaho</u>		
The Amalgamated Sugar Company (C) Nampa, ID	Nampa	Q
Paul, ID	Mini-Cassia	Q
Twin Falls, ID	Twin Falls	Q
Phoenix, AZ	Ten Mile ^c	Q
<u>Illinois</u>		
Marblehead Lime Company (HQ) Chicago, IL	South Chicago Thornton Buffington McCook	Q, H DL, DH, DB Q DL
Vulcan Materials Company Countryside, IL	Indiana Harbor	Q
Inland Steel Company (C) E. Chicago, IN		
<u>Iowa</u>		
Linwood Mining & Minerals Corp. Davenport, IA	Linwood (UG)	Q, H

TABLE C-3. (continued)

Company/headquarters location	Plant location/name	Type of lime produced
Kentucky		
Dravo Lime Company (HQ) Pittsburgh, PA	Black River Div. (UG) Mayesville Div. (HG)	Q, H Q
Louisiana		
Dravo Lime Company (HQ) Pittsburgh, PA	Pelican ^b	H
USG Corp. (HQ) Chicago, IL	New Orleans	Q, H
Massachusetts		
Lee Lime Corp. Lee, MA	Lee	DL, DH
Pfizer, Inc. Adams, MA	Adams	Q
Michigan		
Detroit Lime Company Detroit, MI	River Rouge	Q
The Dow Chemical Company (C) Ludington, MI	Ludington	DL
Marblehead Lime Company (HQ) Chicago, IL	River Rouge	Q
Michigan Sugar Company (C) Saginaw, MI	Brennan	Q, H
	Sebawaing	Q
	Carrollton	Q
	Crosswell	Q
	Caro	Q
Monitor Sugar Company (C) Bay City, MI	Bay City	Q
Minnesota		
American Crystal Sugar Company (C) Moorhead, MN	Moorhead	Q
	Crookston	Q
	East Grand Forks	Q
Southern Minn. Sugar Corp. (C) Renville, MN	Renville	Q
Missouri		
Ash Grove Cement Company Springfield, MO	Springfield	Q, H
Mississippi Lime Company (HQ) Alton, IL	Ste. Genevieve (UG)	Q, H
Resco Products of Missouri, Inc. (HQ) Clearfield, PA	Bonne Terre	DL, Q, DB
Montana		
Continental Lime, Inc. Townsend, MT	Indian Creek	Q
Holly Sugar Corp. (C) Colorado Springs, CO	Sidney	Q
Western Sugar Company Billings, MT	Billings	Q
Nebraska		
Western Sugar Company (C) Bayard, NE	Bayard	Q
Mitchell, NE	Mitchell	Q
Scottsbluff, NE	Scottsbluff	Q
Nevada		
Chemstar Lime, Inc. (HQ) Phoenix, AZ	Apex Henderson	Q, H DL, DH
Continental Lime, Inc. Wendover, NV	Pilot Peak	Q

TABLE C-3. (continued)

Company/headquarters location	Plant location/name	Type of lime produced
<u>North Dakota</u>		
American Crystal Sugar Company (C) Drayton, ND	Drayton	Q
Hillsboro, ND	Hillsboro	Q
Minn-Dak Farmers Corp. (C) Wahpeton, ND	Minn-Dak	Q
<u>Ohio</u>		
Elkem Metals Company (C) Ashtabula, OH	Ashtabula	Q
GenLime Group LP Genoa, OH	Genoa	DL, DH
The Great Lakes Sugar Company (C) Fremont, OH	Fremont	Q
Huron Lime Company Huron, OH	Huron	Q
LTV Steel (C&S) Grand River, OH	Grand River	Q
Martin Marietta (C&S) Woodville, OH	Woodville	DL, DB
National Lime & Stone Company Findlay, OH	Carey	DL, DH
Ohio Lime Company Woodville, OH	Woodville Millersville	DL DL
<u>Oklahoma</u>		
St. Clair Lime Company Oklahoma City, OK	Marble City (UG)	Q, H
<u>Oregon</u>		
The Amalgamated Sugar Company (C) Nyssa, OR	Nyssa	Q
Ash Grove Cement Company Portland, OR	Portland	Q, H
<u>Pennsylvania</u>		
J.E. Baker Company (C&S) York, PA	York	DB
Bellefonte Lime Company Bellefonte, PA	Bellefonte	Q, H
Centre Lime & Stone Company Pleasant Gap, PA	Pleasant Gap	Q, H
Con Lime Company Bellefonte, PA	Bellefonte (UG)	Q, H
Corson Lime Company Plymouth Meeting, PA	Plymouth Meeting	DL, DH
Mercer Lime & Stone Company Pittsburgh, PA	Branchton	Q, H
Warner Company Devault, PA	Cedar Hollow	DL, DH
Wimpey Minerals PA, Inc. Annville, PA	Hanover Annville	DL, Q Q, H
<u>Puerto Rico</u>		
Puerto Rican Cement Company, Inc. Ponce, PR	Ponce	Q, H
<u>South Dakota</u>		
Pete Lien & Sons, Inc. Rapid City, SD	Rapid City	Q, H

TABLE C-3. (continued)

Company/headquarters location	Plant location/name	Type of lime produced
Tennessee		
Bowater Southern Paper Corp. (C) Calhoun, TN	Calhoun	Q
Tenn Luttrell Company Luttrell, TN	Luttrell (UG)	Q, H
Texas		
APG Lime Corp. New Braunfels, TX	New Braunfels	Q, H, DL, DH
Austin White Lime Company Austin, TX	McNeil	Q, H
Chemical Lime, Inc. Clifton, TX	Clifton	Q, H
Holly Sugar Corp. (C) Colorado Springs, CO	Marble Falls	DL
Redland Stone Products Company San Antonio, TX	Hereford	Q
Texas Lime Company Cleburne, TX	San Antonio No. 1 Round Rock ^d	Q, H Q, H Q, H
Utah		
Chemstar Lime, Inc. (HQ) Phoenix, AZ	Dolomite	DL, DH
Continental Lime, Inc. Delta, UT	Cricket Mountain	Q
M.E.R.R. Corp. Grantsville, UT	Marblehead Mt. ^e	DL
Virginia		
APG Lime Corp. Ripplemead, VA	Kimballton (UG)	Q, H
Chemstone Corp. Strasburg, VA	Dominion	Q, H
W.S. Frey Company, Inc. York, PA	Clearbrook	Q
Riverton Corp. (C) Riverton, VA	Riverton	H
Shenvalley Lime Corp. Stephens City, VA	Stephens City ^b	H
Virginia Lime Company Ripplemead, VA	Kimballton (UG)	Q, H
Washington		
Northwest Alloys, Inc. (C) Addy, WA	Addy	DL
Continental Lime, Inc. Tacoma, WA	Tacoma	Q, H
West Virginia		
Germany Valley Limestone Company Riverton, WV	Riverton	Q, H
Wisconsin		
CLM Corp. (HQ) Duluth, MN	Superior	Q, H
Rockwell Lime Company Manitowoc, WI	Manitowoc	DL, DH
Western Lime & Cement Company West Bend, WI	Green Bay Eden	Q, H DL, DH

TABLE C-3. (continued)

Company/headquarters location	Plant location/name	Type of lime produced
Wyoming		
Holly Sugar Company (C)	Torrington	Q
Colorado Springs, CO	Worland	Q
The Western Sugar Company (C)		
Lovell, WY	Lowell	Q

KEY:

- C = Lime plant is operated predominantly for captive consumption.
 C&S = Captive and sales--captive consumption with significant commercial sales.
 DB = Refractory, dead-burned dolomite.
 DH = Dolomitic hydrate.
 DL = Dolomitic quicklime.
 H = Hydrated lime.
 HQ = Headquarters address.
 Q = Quicklime.
 UG = Underground mine.

^aExcludes regenerated lime.

^bHydrating plant only.

^cNew plant, scheduled to come on-line August 1992.

^dPlant did not operate in 1991; it has been mothballed.

^eClosed December 1991, last shipments made May 1992.

APPENDIX D.

CRUDE OIL DISTILLATION CAPACITY

Refiners' Operable Atmospheric Crude Oil Distillation Capacity as of January 1, 1992

Refiner	Barrels per Calendar Day	Refiner	Barrels per Calendar Day
Companies with Capacity Over 100,000 bbl/day			
Chevron U.S.A. Inc.	1,503,700	Toledo, Ohio	125,000
Port Arthur, Texas	315,900	Tulsa, Oklahoma	85,000
Peacogoville, Mississippi	285,000	Sun Refining & Marketing	
El Segundo, California	254,000	Philadelphia, Pennsylvania	130,000
Richmond, California	220,000	Petroleos De Venezuela	479,400
Philadelphia, Pennsylvania	175,000	Cargo Petroleum Corp.	
Port Arthur, New Jersey	80,000	Lake Charles, Louisiana	305,000
El Paso, Texas	68,000	Champion Refining & Chemical Inc.	
Honolulu, Hawaii	52,800	Corpus Christi, Texas	130,000
Salt Lake City, Utah	45,000	Sevenside Oil Co. ^a	
		Paulsboro, New Jersey	44,400
Exxon Co. U.S.A.	1,167,000	Atlantic Richfield Co.	424,500
Baton Rouge, Louisiana	421,000	Arco Products Co.	
Baytown, Texas	368,000	Los Angeles, California	223,000
Linden (Bayway), New Jersey	170,000	Fernside (Cherry Point), Washington	174,500
Berkeley, California	128,000	Arco Alaska Inc.	
Billings, Montana	42,000	Prudhoe Bay, Alaska	15,000
		Anchorage, Alaska	12,000
Amoco Oil Co.	982,000	E I Du Pont de Nemours & Co.	412,000
Texas City, Texas	433,000	Conoco Inc.	
Whiting, Indiana	370,000	Woodlake, Louisiana	186,000
Mandan, North Dakota	68,000	Ponca City, Oklahoma	149,000
Yorktown, Virginia	53,000	Billings, Montana	48,600
Salt Lake City, Utah	40,000	Commerce City, Colorado	48,000
Savannah, Georgia	28,000	Santa Maria, California	9,500
Shell Oil Co.	968,800		
Wood River, Illinois	274,000	Ashland Oil Inc.	348,500
Deer Park, Texas	218,900	Cattletown, Kentucky	213,400
Harco, Louisiana	215,000	St. Paul, Minnesota	87,100
Martinez, California	144,100	Canton, Ohio	68,000
Anacortes, Washington	89,300		
Odeasa, Texas	28,600	Unocal Corp.	341,100
		Wilmington (Los Angeles), California	228,000
Mobil Oil Corp.	838,000	Redwood (San Francisco), California	73,100
Beaumont, Texas	275,000	Arroyo Grande (Santa Maria), California	40,000
Johet, Illinois	180,000		
Chalmette, Louisiana	160,000	Koch Industries Inc.	328,000
Torrance, California	123,000	St. Paul (Pine Bend), Minnesota	200,000
Paulsboro, New Jersey	100,000	Corpus Christi, Texas	126,000
BP America Inc.	741,400		
BP Oil Corp.		Texas Refining & Marketing Inc.	324,000
Belle Chasse (Alliance), Louisiana	219,000	Anacortes (Puget Sound), Washington	132,000
Marcus Hook, Pennsylvania	168,000	El Dorado, Kansas	80,000
Lima, Ohio	145,000	Wilmington (Los Angeles), California	64,000
Toledo, Ohio	126,100	Bakersfield, California	48,000
Fernside, Washington	84,300		
USX Corp. ^a	620,000	Phillips Petroleum Co.	305,000
Marathon Oil Co.		Phillips 66 Co.	
Caryville, Louisiana	258,000	Sweeny, Texas	175,000
Robinson, Illinois	175,000	Borger, Texas	106,000
Detroit, Michigan	70,000	Woods Cross, Utah	25,000
Texas City, Texas	70,000		
Indianapolis, Indiana ^b	50,000	Trans-America Natural Gas Corp.	
		Trans-American Refining Co.	
Star Enterprise	615,000	Norco (Orad Hope), Louisiana	300,000
Port Arthur/Nacoches, Texas	250,000		
Convent, Louisiana	225,000	Solonace Inc.	290,500
Delaware City, Delaware	140,000	Pharos Refining Inc. ^a	
		Texas City, Texas	119,800
Sun Co. Inc.	615,000	Houston, Texas	70,900
Marcus Hook, Pennsylvania	175,000	Krotz Springs, Louisiana	60,000
		Saint Rose, Louisiana	40,000

See footnote at end of table

Refiners' Operable Atmospheric Crude Oil Distillation Capacity as of January 1, 1992
(Continued)

Refiner	Barrels per Calendar Day	Refiner	Barrels per Calendar Day
Coastal Corp., The	275,300	Horsham Corp.	121,800
Coastal Refining & Marketing Inc.		Clark Oil & Refining Corp.	
Corpus Christi, Texas	85,000	Blue Island, Illinois	64,800
El Dorado, Kansas	30,400	Harford, Illinois	57,000
Wichita, Kansas	28,800	Total	13,760,400
Coastal Eagle Point Oil Co.		Companies with Capacity	
Westville, New Jersey	104,500	30,001 to 100,000 bbls/d	
Coastal Mobile Refining Co.			
Chickasaw, Alabama	26,600	Pacific Resources Inc.	
Lyondell Petrochemical Co.		Hawesman Independent Refinery Inc.	
Houston, Texas	265,000	Ewa Beach, Hawaii	93,500
Fine Oil & Chemical Co.	199,000	Farmstead Industries Inc.	
Port Arthur, Texas	144,000	Colleyville, Kansas	82,800
Big Spring, Texas	55,000	Phillipsburg, Kansas	26,400
Total Petroleum Inc.	197,600	LL&E Petroleum Marketing	
Ardmore, Oklahoma	68,000	Saratoga (Mobile), Alabama	80,000
Arkansas City, Kansas	58,000	National Cooperative Refinery Association	
Alma, Michigan	48,600	McPherson, Kansas	75,800
Colorado Refining Co.		Tecora Petroleum Corp.	
Commerce City, Colorado	28,000	Ketchikan, Alaska	72,000
Masco Petroleum Inc.	192,600	Pennzoil Co. Inc.	69,800
North Pole, Alaska	118,500	Pennzoil Producing Co.	
Memphis, Tennessee	76,000	Shreveport, Louisiana	48,200
Diamond Shamrock Refining & Marketing Co.		Roseville, Pennsylvania	18,700
Sunny (McKee), Texas	112,000	Roosevelt, Utah	8,000
Three Rivers, Texas	53,000	American Ultramar Ltd	
Kem-McGee Corp.	158,800	Ultramar Refining	
Southwestern Refining Co. Inc.		Wilmington, California	68,000
Corpus Christi, Texas	104,000	Holly Corp.	63,700
Kem-McGee Refining Corp.		Navajo Refining Co.	
Wynnewood, Oklahoma	45,000	Artesia, New Mexico	57,000
Cotton Valley, Louisiana	7,800	Montana Refining Co.	
Crown Central Petroleum Corp.		Great Falls, Montana	8,700
Pasadena, Texas	155,000	Unifed Refining Co.	
La Gloria Oil & Gas Co.		Warren, Pennsylvania	60,000
Tyler, Texas	55,000	Castle Energy Corp.	
Uno-Ven Co.		Indian Refining	
Lemont (Chicago), Illinois	147,000	Lawrenceville, Illinois	55,000
Tresco Corp.		The Coastal Corp/Sinochem	
Tresco Refining Co.		Pacific Refining Co.	
Marina (Avon), California	131,900	Merced, California	55,000
Sindler Oil Corp.	128,500	El Paso Refinery, L.P.	
Sincar, Wyoming	54,000	El Paso, Texas	50,000
Tulsa, Oklahoma	50,000	Placid Refining Co.	
Little America Refining Co.		Port Allen, Louisiana	48,500
Evansville (Casper), Wyoming	24,500	Lion Oil Co.	
Murphy Oil U.S.A. Inc.	128,200	El Dorado, Arkansas	48,000
Mercus, Louisiana	95,000		
Superior, Wisconsin	33,200		

See footnote at end of table.

Refiners' Operable Atmospheric Crude Oil Distillation Capacity as of January 1, 1992
(Continued)

Refiner	Barrels per Calendar Day	Refiner	Barrels per Calendar Day
Thifty Oil Co. Golden West Refining Co. Santa Fe Springs, California	47,000	San Joaquin Refining Co. Inc. Bakersfield, California	24,300
Paramount Acquisition Corp. Paramount Petroleum Corp. Paramount, California	46,500	Hunewey Refining Co.	24,100
Powerline Oil Co. Santa Fe Springs, California	45,000	Berrios, California	8,600
Pride Refining Inc. Abilene, Texas	42,750	Wilmington, California	5,500
Cirilo Brothers Oil Co. Cibro Petroleum Products Inc. Albany, New York	41,880	Sunbelt Refining Co. Coolidge, Arizona	10,000
Conex Laurel, Montana	41,480	Plying J Petroleum Inc. Big West Oil Co. North Salt Lake, Utah	24,000
Frontier Refining Co. Cheyenne, Wyoming	38,870	Kern Oil & Refining Co. Bakersfield, California	21,400
Hunt Consolidated Inc. Hunt Refining Co. Tuscaloosa, Alabama	33,500	Countryside Cooperative Inc. ^g Mount Vernon, Indiana	21,200
Time Oil Co. U.S. Oil & Refining Co. Tacoma, Washington	32,400	United Refining of Phoenix Texas United Refining Corp. ^h Norton, Texas	20,900
Total	1,291,220	Ergon Inc. Vicksburg, Mississippi	20,600
Companies with Capacity 15,001 to 30,000 barrels		Giant Industries of Arizona Inc. Giant Refining Co. Gallup, New Mexico	20,000
Amerasia Hess Corp. Purvis, Mississippi	30,000	Barnett Refining Corp.	17,500
Honda Co. Fletcher Oil & Refining Co. Carson, California	29,675	Thomas (Custer), Oklahoma	10,500
Gold Line Refining Ltd. ⁱ Lake Charles, Louisiana	27,600	Vicksburg, Mississippi ⁱ	7,000
Petroserve Ltd. Tribunary Corpus Christi, Texas	27,000	Gary Williams Co. Bloomfield Refining Co. Bloomfield, New Mexico	16,800
Valero Refining Co. Corpus Christi, Texas	25,000	VGS Corp.	16,800
Crysan Corp.	24,400	Southland Oil Co. Sardisville, Mississippi	11,000
Crysan Refining Inc. Woods Cross, Utah	12,500	Lumberton, Mississippi	5,800
Sound Refining Inc. Tacoma, Washington	11,900	Endacore Inc.	16,000
		Dubach Gas Co. Dubach, Louisiana	8,500
		Lisbon, Louisiana ^j	7,500
		Chemical Refining Corp. Long Beach, California	14,200
		CAS Refining Co. Jennings (Mormontau), Louisiana	13,500
		Longview Refining Associates Longview, Texas	13,300
		Wyoming Refining Co. Newcastle, Wyoming	12,555

See footnotes at end of table.

Refiners' Operable Atmospheric Crude Oil Distillation Capacity as of January 1, 1992
(Continued)

Refiner	Barrels per Calendar Day	Refiner	Barrels per Calendar Day
Transworld Oil U.S.A. Inc. Calcasieu Refining Co. Lake Charles, Louisiana	12,500	WSP Partners L.P. Petrowest Pennsylvania, Inc. Farmer's Valley (Greensport, Pennsylvania)	6,700
Sabine Resources Group Stonewall, Louisiana	12,000	Primary Corp. Richmond, Virginia	6,100
World Oil Co. Sutland Refining Corp. Bakersfield, California	12,000	Calumet Lubricants Co. L.P. Princeton, Louisiana	6,000
Bechtel Investment Inc. Petro Source Refining Partners Eagle Springs, Nevada	11,500	Marin Gas Sales Inc. Berry Petroleum Co. Stephens, Arkansas	5,700
..... Tonopah, Nevada	4,500	Young Refining Corp. Douglasville, Georgia	5,540
Custer State Corp. Newell, West Virginia	11,500	Somerset Refinery Inc. Somerset, Kentucky	5,500
Grant Trading Co. Eco Asphalt Inc. Long Beach, California	10,550	Phoenix Refining Co. Saint Mary's, West Virginia	4,500
Total	538,890	Oil Holdings Inc. Torrey Inc. Oxnard, California	4,000
Companies with Capacity 10,000 barrels or Less		Thrifty Co. Bloomfield, New Mexico	4,000
Landmark Petroleum Inc. Fruita, Colorado	10,000	Crystal Refining Co. Carson City, Michigan	3,000
Witco Corp. Bradford, Pennsylvania	9,915	GNC Energy Corp. Greensboro, North Carolina	3,000
Asphalt Materials Laketon Refining Corp. Laketon, Indiana	8,700	Howell Corp. Howell Hydrocarbons & Chemical Inc. ^a San Antonio, Texas	1,800
Lundby Thegard Co. South Gate, California	8,100	Petrolite Corp. Kilgore, Texas	1,000
Anchor Gasoline Corp. Canal Refining Co. Church Point, Louisiana	8,000	Total	123,685
Three B Oil Co. Rattlesnake Refining Corp. Wichita, Texas	8,000	U.S. Total	15,896,155
Cross Oil & Refining Co. Inc. Smelterview, Arkansas	7,000		
Petro Star Inc. North Pole, Alaska	7,000		

- ^a Formerly U.S. Steel Corp.
- ^b Formerly Rock Island Refining
- ^c Formerly Seaview Petroleum Co., L.P.
- ^d Formerly Hill Petroleum Co.
- ^e Formerly Coastal Dairy Refining Co.
- ^f Formerly American Industrial Refinery Inc.
- ^g Formerly Indiana Form Bunker Corp. Acen.
- ^h Formerly Lead Petroleum Corp.
- ⁱ Formerly Petro Source Resources Inc.
- ^j Formerly Calcasieu Gasoline Co.

- ^k Formerly Howell Hydrocarbons Corp.
 - ^l Refinery was reactivated on January 1, 1992.
- barrel = barrels per calendar day.

Sources: United States Refining Capacity, January 1, 1990
National Petroleum Refineries Association, Washington, D.C.

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16. ABSTRACT <p>To assist groups interested in inventorying air emissions of various potentially toxic substances, EPA is preparing a series of documents such as this to compile available information on sources and emission of these substances. This document deals specifically with mercury and mercury compounds. Its intended audience includes Federal, State and local air pollution personnel and others interested in locating potential emitters of mercury and in making gross estimates of air emissions therefrom.</p> <p>This document presents information on (1) the types of sources that may emit mercury and mercury compounds, (2) process variations and release points that may be emitted within these sources, and (3) available emissions information indicating the potential for mercury and mercury compound releases into the air from each operation.</p>					
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