United States
Environmental Protection
Agency

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

EPA-453/R-98-003
June 1998

Air

PETROLEUM REFINERIES - BACKGROUND INFORMATION FOR PROPOSED STANDARDS

Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Recovery Units

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NESHAP

EPA- 453/R-98-003

Petroleum Refinery – Background Information for Proposed Standards

Catalytic Cracking (Fluid and Other) Units, Catalytic Reforming Units, and Sulfur Recovery Units

Emissions Standards Division

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

June 1998

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Environmental Protection Agency

Background Information for Proposed Standards National Emission Standards for Hazardous Air Pollutants for Petroleum Refinery Process Vents

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1. The proposed standards would regulate emission of hazardous air pollutants (HAP) emitted from Petroleum Refinery process vents. Only those process vents that are part of major sources under Section 112(d) of the CAA would be regulated. The recommended standards would reduce emissions of xxx of the chemicals identified in the CAA list of hazardous air pollutants.

2. Copies of this document have been sent to the following Federal Departments: Labor, Health and Human Services, Defense, Office of Management and Budget, Transportation, Agriculture, Commerce, Interior, and Energy; the National Science Foundation; and the Council on Environmental Quality. Copies have also been sent to members of the State and Territorial Air Pollution Program Administrators; the Association of Local Air Pollution Control Officials; EPA Regional Administrators; and other interest parties.

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4. Copies of this document may be obtained from:

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CONTENTS

CONTENTS (Continued)

LIST OF TABLES

LIST OF TABLES (Continued)

LIST OF FIGURES

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1.0 INTRODUCTION

1.1 BACKGROUND

Title III of the 1990 Amendments to the Clean Air Act (CAA) substantially revised section 112 of the Act regarding the development of National Emission Standards for Hazardous Air Pollutants (NESHAP). To implement the congressional directives of Title III, the U.S. Environmental Protection Agency (EPA) has initiated a program to develop NESHAP for certain categories of stationary air emission sources that emit one or more of the hazardous air pollutants (HAP) listed in section 112(b) of the CAA.

1.2 PETROLEUM REFINERY VENTS NESHAP

On July 16, 1992, EPA published a list of all source categories emitting HAP (57 FR 31576) and included Petroleum Refineries among the listed source categories. On August 18, 1995, EPA promulgated a NESHAP for the petroleum refinery source category primarily for organic HAP emission sources (60 FR 43244). In the 1995 petroleum refinery NESHAP, EPA specifically excluded three process vents from the NESHAP because of the unique characteristics of the inorganic emissions from each of these vents and stated that "these emission points are included in a separate source category under a separate schedule." These three process vents are the subject of this rulemaking entitled "NESHAP: Petroleum Refineries - FCC Units, Reformers, and Sulfur Plants." The emission sources considered under this rulemaking include: 1) the catalyst regeneration process vent(s) from the catalytic cracking unit (CCU); 2) the catalyst regeneration process vent(s) from the catalytic reforming unit (CRU); and the process vent(s) for the sulfur recovery plant.

1.3 PURPOSE OF THIS DOCUMENT

In developing NESHAP, the EPA evaluates different strategies for reducing air emissions from the source category. For selected control strategies, the EPA develops emission and control cost impacts to support in the development of the NESHAP. This technical support document (TSD) presents the information and methods used by EPA to perform the control strategy impact analysis.

Chapter 2 presents a brief overview of the petroleum refinery industry as pertaining to the CCU, CRU, sulfur recovery processes. Chapter 3 provides a more detailed description of each of the processes, the type of HAP emitted, the process emissions points. Chapter 4 describes the control technologies available for reducing HAP emissions from each of the process vents. The procedures used to estimate current (baseline) and controlled emission are provided in Chapter 5; the procedures used to estimate the other environmental and energy impacts associated with the control strategies are provided in Chapter 6. The options considered for monitoring the emission points are discussed in Chapter 7. Chapter 8 describes the methods and procedures used to estimate the control cost impacts associated with the selected control and monitoring strategies.

2.0 INDUSTRY DESCRIPTION

This chapter presents a brief overview of the petroleum refinery industry in general, with particular industry descriptions of catalytic cracking units (CCUs), catalytic reforming unit (CRUs), and the sulfur recovery plants.

2.1 PETROLEUM REFINERY INDUSTRY PROFILE[1]

There are approximately 162 petroleum refineries in 33 States nationwide (see Table 2-1). These 162 refineries process 15.4 million barrels of crude oil daily. As seen in Figure 2-1, the following three States dominate U.S. crude oil refining: California (14.2 percent of the refineries and 12.3 percent of the crude capacity); Louisiana (11.7 percent of the refineries and 15.7 percent of the crude capacity); and Texas (17.3 percent of the refineries and 26.1 percent of the crude capacity). Together, these three States represent 43 percent of the U.S. refineries and 54 percent of the total nationwide crude oil processing capacity.

There are 36 petroleum refineries with crude oil processing capacities of 20,000 barrels per calendar day (b/cd) or less. Most of these small capacity refineries do not have the processes of interest for this source category (only 3 have a CCU and 8 have a CRU). In the petroleum refinery industry, however, a small business is defined as any business that processes less than 75,000 b/cd of crude oil and employs less than 1,500 people corporately. There are 94 petroleum refineries that process less than

Table 1. U.S. Refineries–State Capacities as of January 1, 1997[a]

State	No. of plants	Crude capacity, b/cd	Catalytic crackling, b/cd	Catalytic reforming, b/cd	Sulfur Production , t/d
Alabama	3	134,225	0	26,480	131
Alaska	6	283,000	0	12,000	15
Arkansas	3	65,200	19,100	12,400	88
California	23	1,898,815	608,470	428,260	1,768
Colorado	2	85,500	27,000	19,000	44
Delaware	1	140,000	63,000	45,900	448
Georgia	2	34,000	0	0	0
Hawaii	2	149,000	21,000	13,000	20
Illinois	6	909,550	322,200	336,920	435
Indiana	3	435,990	157,050	92,000	370
Kansas	3	283,350	79,120	60,470	81
Kentucky	2	224,800	97,000	43,195	0
Louisiana	19	2,417,290	885,900	463,200	2,552
Michigan	3	121,200	45,500	27,900	25
Minnesota	2	355,000	108,810	75,795	750
Mississippi	4	336,800	63,000	71,000	1,067
Montana	4	143,850	53,000	31,500	0
Nevada	1	7,000	0	0	0
New Jersey	6	674,000	282,700	118,400	0
New Mexico	3	97,600	32,331	31,800	2
North Dakota	1	58,000	24,700	11,500	15
Ohio	4	499,650	173,550	153,200	0
Oklahoma	5	403,000	109,700	88,050	95
Pennsylvania	6	574,400	122,500	128,488	0
Tennessee	1	105,000	50,000	16,000	42
Texas	28	4,019,600	1,588,300	1,133,600	4,211
Utah	5	159,500	43,400	31,400	46
Virginia	1	56,700	25,700	10,800	66
Washington	7	587,250	117,500	126,300	241
West Virginia	1	10,500	0	3,300	1
Wisconsin	1	36,000	10,400	7,600	15
Wyoming	4	126,825	49,200	29,125	2
TOTAL	162	15,432,595	5,180,583	3,648,583	12,530

[a] Data obtained from Reference 2, but omits one facility in Oregon that has no reported crude capacity (apparently an asphalt plant). Data also omits Tosco Refining Co. in Marcus Hook, PA (180,500 b/cd capacity) that was idled in 1996; it is expected to restart mid-1997.

75,000 b/cd of crude oil. Approximately half of these are considered to be small businesses based on the number of corporate employees as reported in an industry survey.[3] There are 24 petroleum refineries with crude oil processing capacities of 200,000 b/cd or more, and these 24 refineries represent almost 44 percent of the U.S. crude oil refining capacity.

Over the past 5 years the total nationwide petroleum refining capacity has dropped slightly, but the actual crude oil processing rates have risen slightly. The total petroleum refining capacity was 15.6 million b/cd in 1990 compared to 15.3 million b/cd in 1995. During the same time frame, the total number of operating refineries fell from 184 to 173. However, the actual crude oil processing rate increased from 13.6 million b/cd in 1990 to 14.1 million b/cd in 1995. Thus, the U.S. petroleum refining capacity utilization has increased from 87 percent in 1990 to 92 percent in 1995.[4]

Future trends in the petroleum refining industry are expected to mirror the past five years. According to U.S. Department of Energy and Commerce projections, refinery shutdowns are expected to continue, but the crude oil processing rate is expected to remain relatively stable as a result of increased capacity utilization at existing facilities. The demand for refined petroleum products is expected to grow an average of 1.5 percent per year, which is slower than the expected growth rate of the economy.[5]

2.2 PETROLEUM REFINERY INDUSTRY DESCRIPTION

2.2.1 Catalytic Cracking Units[6]

The nationwide petroleum refinery catalytic cracking (fluid and other) charge capacity was 5.18 million b/cd in January 1997.[1] There are 105 petroleum refineries that operate a total of 117 CCU [either fluid and/or other (non-fluidized) CCU]. However, fluid CCUs dominate the CCU processes in the petroleum refinery industry. There are only 7 refineries that reported operating a non-fluidized

CCU, only 4 of which reported operating only a non-fluidized CCU, and non-fluidized CCUs accounted for only 2.9 percent of the total catalytic cracking process charge rate.

There are 9 refineries that reported catalytic cracking charge capacities of less than 10,000 b/cd. There are 8 refineries that reported charge capacities of greater than 100,000 b/cd; half of these refineries have more than one catalytic cracking unit.

2.2.2 Catalytic Reforming Units[7]

The total nationwide catalytic reforming charge capacity was 3.65 million b/cd in January 1997. There are 124 refineries that operate some form of CRU. There are three major types of CRU catalytic regeneration processes: semi-regenerative; cyclic; and continuous (see Section 3.2 for CRU process description). There are 111 refineries, representing 49 percent of reforming capacity, that use semi-regenerative process technologies; 23 refineries with 24 percent of reforming capacity employed the cyclic process technologies; and 32 refineries with 27 percent of reforming capacity employed the continuous process technologies.

There are 15 petroleum refineries that have reforming capacities of 5,000 b/cd or less, and 14 petroleum refineries that have reforming capacities of 50,000 b/cd or more.

2.2.3 Sulfur Plant Units[8]

Production of sulfur (all forms measured as pure elemental sulfur) from petroleum refineries was reported at 2,940 thousand Mg in 1985 and 4,200 thousand Mg in 1990. There are 130 U.S. refineries that report operating some form of sulfur production units (in 1992), representing a total sulfur production capacity of 20,500 Mg/day.

There are 52 refineries that have sulfur production capacities of less than 50 Mg/day; 24 refineries have sulfur production capacities greater than 300 Mg/day; and 5 refineries have sulfur production capacities greater than 500 Mg/day.

Of the 130 refineries that have sulfur recovery plants, 88 provided the number of sulfur plant trains (units) at the facility; the total number of units reported was 144 sulfur trains; 38 reported multiple trains with 13 reporting 3 or more units.

2.3 REFERENCES

1. Radler, Marilyn, Survey Editor. "1996 Worldwide Refining Survey." <u>Oil and Gas Journal</u>. OGJ Special, December 23, 1996. pp. 49 through 94.

2. Reference 1.

3. U.S Environmental Protection Agency. Responses to Information Collection Request for Petroleum Refineries. Publication No. XXXXX. Office of Air Quality Planning and Standards, Research Triangle Park, NC. 1992.

4. Lidderdale, T., N. Masterson, and N. Dazzo. "U.S. Refining Capacity Utilization." Energy Information Administration, Petroleum Supply Monthly. pp. 33 through 39.

5. U.S Environmental Protection Agency. EPA Office of Compliance Sector Notebook Project - Profile of the Petroleum Refining Industry. Publication No. EPA/310-R-95-013. Office of Enforcement and Compliance Assurance, Washington, DC. September 1995. pp. 10 and 11.

6. Reference 1.

7. Reference 1.

8. 1992 Report on Sulfur Production. <u>Chemical Economics Handbook</u>. 1992.

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3.0 PROCESS DESCRIPTION AND EMISSION POINTS

This chapter presents a description of the processes associated with the three refinery vents of interest: catalytic cracking unit (CCU) catalyst regeneration process vent (CCU vent), the catalytic reforming unit (CRU) catalyst regeneration process vent (CRU vent), and the sulfur recovery plant vent (SRU vent). For each process vent, process descriptions are provided with an emphasis on the sources of hazardous air pollutants (HAP) and a description of the emission release points. Much of the following process descriptions result as a composite of infromation collected during site visits to petroleum refineries (see References 1 through 5). The Petroleum Refinery Enforcement Manual[6] and the EPA Sector Notebook for petroleum refining[7] are also general references for the process descriptions provided in the chapter.

3.1 CATALYTIC CRACKING UNIT (CCU)

The CCU (fluid or other) is used to upgrade the heavy distillates to lighter, more useful distillates such as heating oils or gasoline. The typical CCU system consists of a CCU reactor, a CCU catalyst regenerator (CCUCR), vent gas process equipment for energy recovery and/or emission control, and an exhaust stack (see Figure 3-1). Nearly all CCU systems operate as fluidized-bed reactors and use air or oil gas flow to transport the catalyst between the CCU reactor and the CCUCR. These fluidized CCU systems are

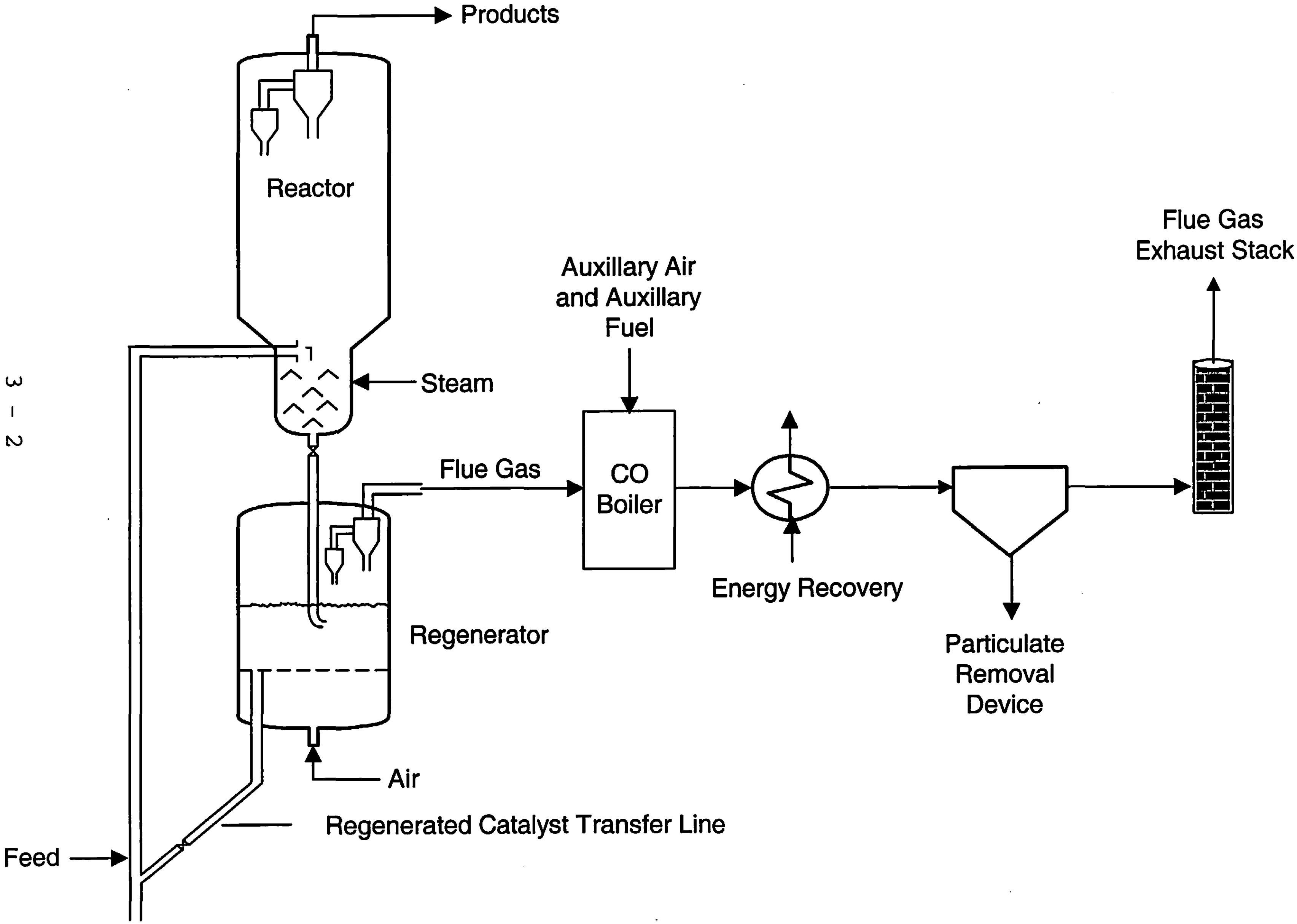


Figure 3-1. Fluid catalytic cracking unit.

commonly referred to as FCCUs (fluid catalytic cracking units), and the process descriptions that follow will focus primarily on FCCU operation due to their dominance in the industry. However, since catalyst regeneration vents for non-fluid CCUs are included in this source category, the term CCU is used throughout this document to refer to both FCCU and other "thermal" CCU (TCCU). The terms FCCU and TCCU will be used to refer to a specific type of CCU.

3.1.1 FCCU Process Description

The FCCU catalyst may be silica-based, alumina-based, or zeolite based fine powder that is easily fluidized in air. Hot catalyst from the regenerator is typically returned to the FCCU reactor in a vertical tube referred to as the riser (see Figure 1). Preheated liquid gas oil is fed to the base of the riser, where it comes into contact with hot catalyst from the regenerator. The gas oil vaporizes at this point of initial contact, and the gas oil vapors rise, carrying the catalyst with them. The gas oil vapors undergo cracking reactions as they mix with the catalyst particles. Some of the reaction products, however, are deposited on the catalyst in the form of coke (carbon), which reduces catalyst activity. The mixture of products and catalyst flows up the riser into the CCU reactor vessel. Current research indicates that most of the cracking reactions take place in the riser. As such the FCCU reactor functions primarily to separate the vapor products from the catalyst.

Catalyst entrained with the vapor products are typically disengaged from the vapor product by flow (impact) impingers followed by cyclone separators. The vapor products pass through the internal cyclones and are vented from the top of the FCCU reactor to a fractionation column for product separation. The disengaged catalyst is collected at the base of the reactor where the catalyst is stripped with steam to remove any hydrocarbons that may have deposited on the catalyst before returning the catalyst to the regenerator.

Spent catalyst collected in the FCCU reactor is continuously returned to the regenerator to burn off coke deposits. After the coke is burned off, the regenerated catalyst flows down a transfer line for reuse and is then introduced to the gas oil feed stream at the beginning of the riser, and the process repeats itself.

The spent catalyst that is returned from the CCU reactor is continuously regenerated by burning off coke that was deposited on the catalyst in the riser and CCU reactor. Air is blown into the regeneration vessel for use in the combustion reaction and to mix (fluidize) the catalyst. The coke deposited on the catalyst serves as the carbon fuel source. There are two basic types of CCU regenerators: **complete combustion** regenerators and **partial combustion** regenerators. In a complete combustion regenerator, the regenerator is typically operated at approximately 1,200 to 1,400°F with excess oxygen and low levels (< 500 ppmv) of carbon monoxide (CO) in the exhaust flue gas. In a partial (or incomplete) combustion regenerator, the regenerator is typically operated at approximately 1,000 to 1,200°F under oxygen limited conditions and relatively high levels (1 to 3 percent) of CO. Small amounts of platinum may be added to the CCUCR to promote combustion; "De-SOx" or other SO_x scavenging additives may be added to reduce SO_x emissions; and fresh catalyst may be added to the CCUCR to maintain catalyst activity and replace catalyst lost from the system. Prior to exiting the CCUCR, catalyst particles entrained with the flue gases are initially removed by internal cyclone separators.

3.1.2 TCCU Process Description

The TCCU process employs catalyst pellets rather than the fine catalyst powder used in FCCUs. The TCCU pellets are roughly 1/8 inch (3,175 μ) long compared to a typical FCCU powder diameter of 85 μ. Due to the size of the catlyst, moving bed catalyst recirculation is used rather than fluidized bed. Figure 3-2 provides a simplified schematic of a typical TCCU. The TCCU catalyst enters the top of the vertical reactor and flows in a plug flow fashion down the reactor bed by gravitational force (refer to Figure 2). Oil feed is introduced near the top of the reactor portion of the TCCU where it mixes with the hot catalyst pellets and flows cocurrent with the catalyst bed. The feed oil vaporizes and the vapors and the cracking reactions occur. The catalyst and vapor products, upon reaching the bottom of the reactor, pass through a vapor disengaging grid. Vapor is disengaged from the catalyst and drawn off by a series of vapor tubes. Purge steam is introduced below the vapor draw off tubes to purge any remaining oil vapor from the catalyst pellets. The purge steam is also removed from the system via the vapor draw off tubes along with the oil vapor products.

Purged catalyst pellets continue to move downward to the regenerator (or kiln) portion of the TCCU. Air is introduced near middle of the regenerator section in a controlled manor to regulate the temperature and coke burn-off rate. The operating pressure in the TCCU regenerator is approximately 3 psig compared to 30 psig for a FCCU regenerator. Flue gas is removed from the system both near the top of the regenerator and near the bottom of the regenerator. Approximately 70 percent of the air feed passes upward through the regenerator and 30 percent flows downward with the catalyst. Flue gas is separated from the catalyst at the bottom of the regenerator is a similar fashion as oil vapor was disengaged from the catalyst at the bottom of the reactor. The flue gas streams combine and either fed to a CO boiler or released directly to the atmosphere through a single stack vent.

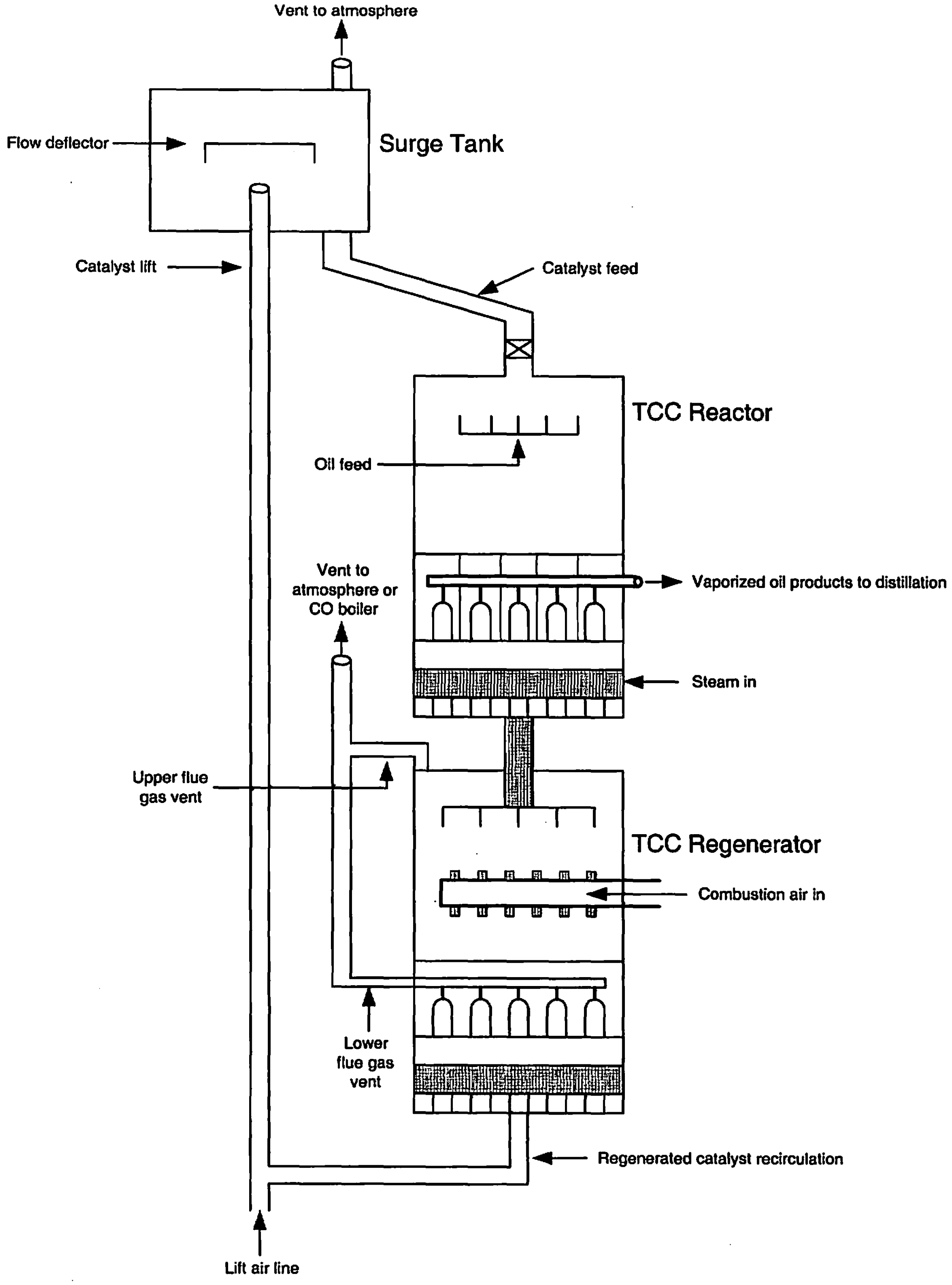


Figure 3-2. Simplified Schematic of non-fluid (thermal) catalytic cracking unit (TCCU).

Below the regenerator, the catalyst flows through a cooler section to cool the catalyst and recover latent heat. The catalyst is then transported to the catalyst surge vessel at the top of the TCCU via catalyst lift pipe. The surge vessel acts both as reservoir for the catalyst and as a catalyst / lift air separator. The lift air is vented from the surge vessel to the atmosphere. Catalyst is fed to the reactor from the surge vessel and the process repeats.

3.1.3 CCU Emission Points

There are two primary vents from the CCU system. The first vent is the product oil gases that exit the CCU reactor. This vent leads to a fractionation column for product separation and is not a direct process vent emission source. Process equipment leaks on this product side of the CCU system result in a loss in product yield and the refineries have an economic incentive to reduce or correct any equipment leaks on the product side of the CCU system.

The second vent from the CCU system is the flue gas exhausted from the CCUCR as a result of burning off coke deposited on the catalyst. This exhaust vent is the primary process emission vent from the CCU system. This vent will be referred to in this document as the CCUCR vent, although other references cited in this document may refer to this vent as the CCU vent, the FCCU vent, or the process vent for FCC units. Note, both FCCU and TCCU have a CCUCR vent.

The CCUCR vent stack flue gas is characterized by low HAP concentrations and large volumes of gas. The final CCUCR vent stack is typically 6 to 16 feet in diameter, depending of the CCU throughput, and 100 feet high. The CCUCR vent from a TCCU are generally smaller, roughly 2 to 3 feet in diameter. Typical volumetric flow rates of flue gas in the CCUCR vent stack range from 50,000 standard cubic feet per minute (scfm) for smaller CCUs to 400,000 scfm or more for larger CCUs. The total HAP concentrations in the CCUCR vent stack flue gas ranges from 0.1 to 1 parts per million by volume (ppmv). HAP that are commonly present in the flue gas from the CCUCR include metals (primarily nickel) and organics (primarily formaldehyde, acetaldehyde, benzene, toluene, xylenes, hexane, and phenol). Other metals that have been detected in the CCUCR vent flue gas include: antimony, cadmium, chromium, cobalt, lead, manganese, and mercury. Other organics that have been detected (or suspected to be) in the CCUCR vent flue gas include: naphthalene, polycyclic organic matter (POM), dioxins, and furans.[8]

The TCCU has an additional emission point from the surge vessel where lift air used to transport catalyst from the bottom to the top of the TCCU is vented to the atmosphere. Catalyst particles may remain entrained with the lift air so there is a potential for the surge tank vent to emit the same metal HAP that are emitted from the CCUCR vent. The relative volume of the lift air flow rate is approximately one-third to one-half the flue gas flow rate from the regenerator. However, due to the relative characteristics of the surge vessel vent and the CCUCR vent, the particulate emissions rate from the surge vessel vent are expected to be roughly equivalent and may be higher than the particulate emissions from the CCUCR vent. No data are currently available regarding the HAP emissions from TCCU surge vessel vent. As such, it is unclear how the overall HAP emissions from the TCCU (CCUCR vent plus the surge tank vent emissions) compare to the CCUCR emissions from a CCU with similar throughput.

The metal HAP are expected to originate as contaminants in the CCU feed that deposit on the catalyst particles. Consequently the metal HAP emission rate may be dependent on the mix of oils and residual used as feed to the CCU. Some CCU feeds are hydrotreated. The hydrotreater removes sulfur, nitrogen, vanadium, nickel and other contaminants from the crude oil feedstocks. This "pretreatment" step prior to the CCU typically helps to improve CCU yield, prolongs catalyst life, and reduces CCU HAP emissions according to industry representatives.[9] Because most of the metal HAP emissions are in the form of particulate matter (PM), PM control devices also reduce metal HAP emissions.

Many of the organic HAP emissions originate as byproducts of coke combustion (e.g., formaldehyde, acetaldehyde, POM, dioxins and furans). It is unclear, however, why the volatile organic HAP (benzene, toluene, xylenes, and hexane) are not destroyed in the CCUCR. These volatile organic HAP may originate as residual oil feed material on the catalysts that somehow vaporize, but do not combust prior to exiting the CCUCR.

Organic HAP emissions from partial combustion regenerators may be expected to be higher due to the lack of sufficient oxygen to completely combust the coke material. However, most partial combustion regenerators employ a CO boiler or incinerator to recover the latent heat energy of the CO in the CCUCR flue gas. At this time, the EPA is collecting data to determine whether a complete combustion CCU system has significantly different HAP emissions from a partial combustion CCU system followed by a CO boiler.

Equipment leaks and fugitive emissions are not anticipated to be significant from the CCUCR flue gas treatment train because of the low concentrations of HAP in this vent stream.

3.2 CATALYTIC REFORMING UNIT (CRU)

3.2.1 <u>CRU Process Description</u>

The catalytic reforming process involves a complicated series of reactions that occur over a catalyst that change the chemical structure of the hydrocarbons. The predominant reaction is the dehydrogenation of naphthenes to form aromatics. The reactions occur over a noble metal catalyst, such as platinum or rhenium. The feedstocks for reforming (referred to as naphtha) are first treated to remove sulfur and other compounds that would poison the reforming catalyst. Because the reforming reaction is endothermic, heat must be continually supplied to the system to maintain optimal reaction temperatures. This is typically accomplished by performing the reaction in a series of reactors and applying heat to the naphtha/product stream through heat exchangers between each reactor.

The reforming products are separated into a gas and a liquid stream. The hydrogen gas is compressed with a portion going back to the reformer; the hydrocarbon stream is sent to a fractionation column for final product separation. As the reaction progresses, deposits accumulate on the catalyst particles and reduce their reactivity. Consequently, the catalyst must be occasionally regenerated.

3.2.2 CRU Catalytic Regeneration Process Description

There are three different methods in which to effect reforming catalyst regeneration. **Semiregenerative** reforming is characterized by shutdown of the reforming unit at specified intervals, or at the operator's convenience, for in situ catalyst regeneration (see Figure 3-3). **Cyclic regeneration** reforming is characterized by continuous or continual regeneration of catalyst in situ by isolating one of the reactors in the series, regenerating the catalyst, then returning the reactor to the reforming operation (see Figure 3-4). **Continuous regeneration** reforming is characterized by the continuous regeneration of part of the catalyst in a special regenerator, followed by continuous addition of this regenerated catalyst to the reactor (see Figure 3-5).

As with the CCU catalyst, the CRU catalyst is regenerated by controlled oxidation (burning) of the coke deposited on the catalyst. In semiregenerative and cyclic regenerators, the CRU reactor(s) are first taken off-line,

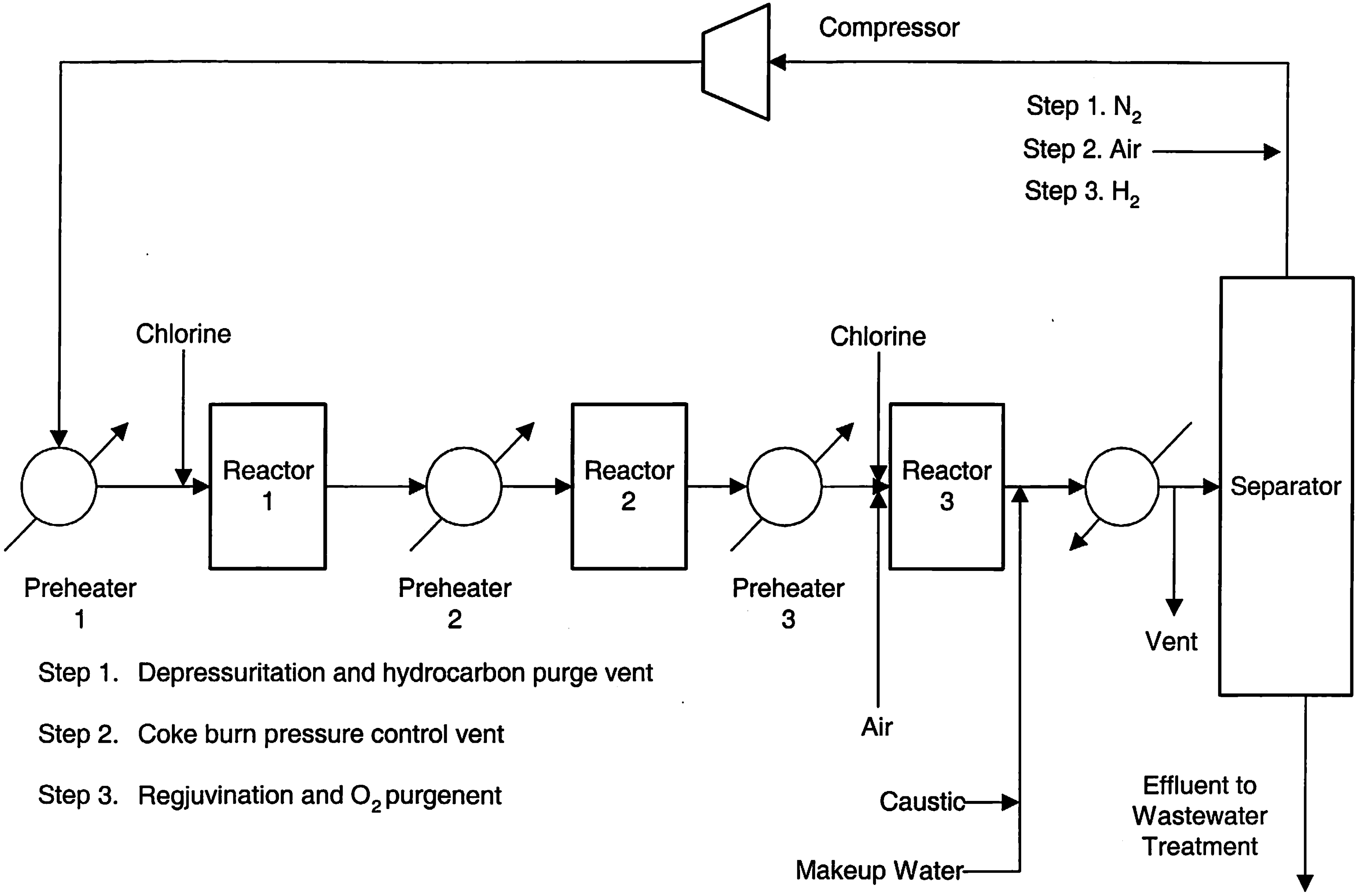
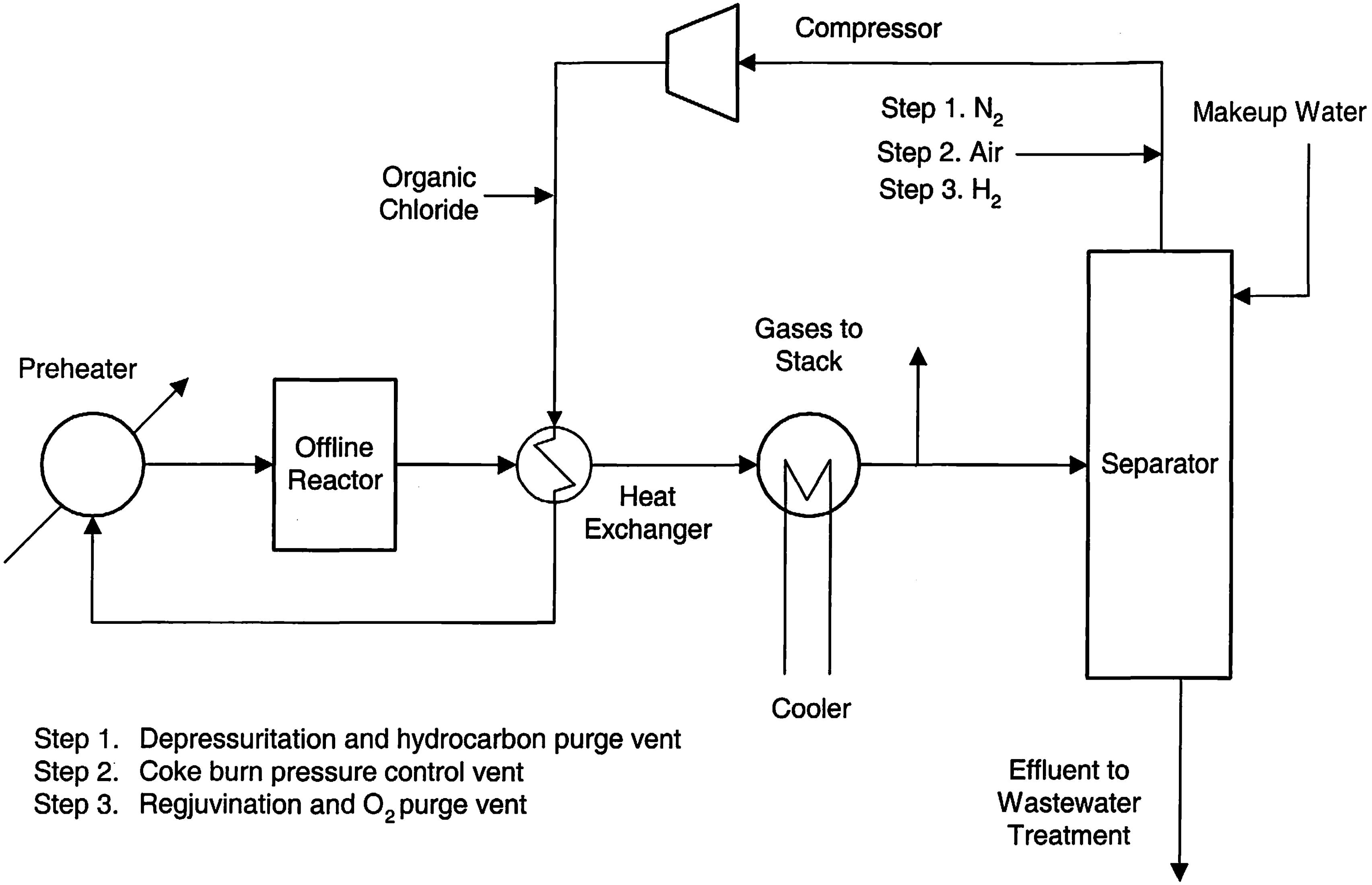


Figure 3-3. Typical regeneration process flow diagram for semi-regenerative catalytic reformers.



Step 1. Depressuritation and hydrocarbon purge vent
Step 2. Coke burn pressure control vent
Step 3. Regjuvination and O_2 purge vent

Figure 3-4. Typical regeneration process flow diagram for cyclic catalytic reformers.

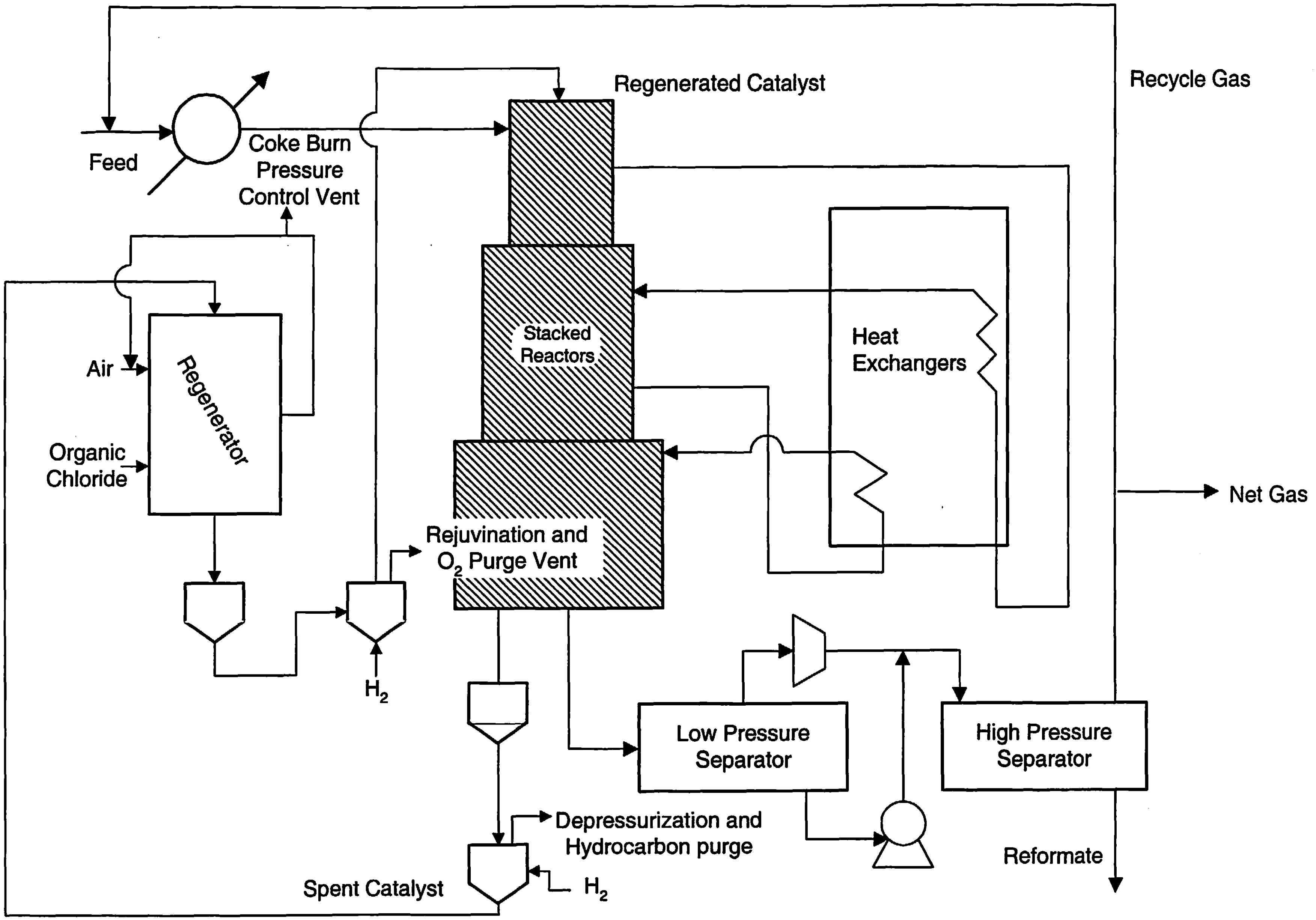


Figure 3-5. Typical process flow diagram for continuous reformers.

the reactor(s) are isolated, and any residual hydrocarbons are purged from the system using nitrogen. This nitrogen purge gas is typically vented to the refinery's flare system. Air is then slowly introduced to the CRU reactor(s) to begin the combustion process, with the coke serving to fuel the process. The flue gas from the CRU coke combustion is typically recirculated, with small amounts of fresh air continuously added to the recirculated air to control the coke burn rate. Excess flue gas from the coke combustion is vented to the atmosphere from a small pipe vent as necessary to maintain the desired pressure within the system.

The combustion process naturally produces some water. The water tends to leach chloride atoms from the catalyst, which reduces the catalyst's performance. Consequently, a chloride source (usually a chlorinated organic such as perchloroethene or trichloroethene) is used to replace the chloride atoms stripped by the water. The chlorination cycle may be performed either as a separate cycle after the coke burn cycle is completed or simultaneously while the coke burn cycle is under way. Once the catalyst is regenerated (i.e., coke burn and chlorination cycles completed), the system is first purged with nitrogen to remove any oxygen and residual chlorination agent from the system, and then purged with hydrogen to reduce the catalyst from the metallic oxide formed during the burn cycle back to its active (elemental) metal state prior to bringing the unit back on-line.

The overall regeneration cycle for semiregenerative systems takes approximately 5 to 15 days depending on the level of other maintenance the CRU requires. The coke burn cycle typically takes between 2 to 5 days. Cycle times between regeneration cycles may range from 6 to 18 months depending on the severity of the CRU reactor operating conditions (which are based on the product mix being produced from the CRU). Regeneration cycles for cyclic systems are typically shorter in duration and more frequent in occurrence than semiregenerative systems. However, both systems are characterized by short, intermittent periods when emissions may occur.

In continuous CRU regeneration, catalyst from the CRU is circulated in semi-continuous fashion (small batches) to the regenerator by a series of small hoppers. These hoppers serve the function of the depressurization and initial purge cycle of the semiregenerative or cyclic systems. A continuous CRU regenerator typically has three sections: a regeneration section, a chlorination section, and a drying section. The first section of the regenerator that the catalyst enters is the regeneration section. In the regeneration section, hot air (at approximately 900 to 1,200°F) is recirculated through the catalyst, with enough fresh air added to maintain a low excess oxygen content (of approximately 1 to 2 percent). As air is added to the recirculating regeneration air line, air must also be vented from the system to maintain the desired pressure in the regeneration air line. This vent is typically vented to the atmosphere; however, a water or caustic scrubber may be used in either the air recirculation line or in the vent line to remove HCl.

In the next section, called the chlorination section, a chloride source (e.g., perchloroethene or trichloroethene) is recirculated through the catalyst to replace any chloride leached from the catalyst in the regeneration section. The regeneration and chlorination sections are separated by a series of baffles to allow catalyst to move from the regeneration section to the chlorination section, but to minimize gas flow between the two sections.

The catalyst from the chlorination section then moves past another series of baffles into the drying section. In this section, hot air is used to strip any chloride agent remaining on the catalyst and dry the catalyst. After the dying section, the catalyst is returned to the CRU reactor by another series of small hoppers. These hoppers serve the function of the final purge cycle (to remove oxygen and create a reducing atmosphere) of the semiregenerative or cyclic systems.

3.2.3 CRU Emission Points

The CRU system is essentially a sealed system except for the catalyst regeneration cycles. Although the location of the emission point might vary depending on whether catalyst regeneration is semiregenerative, cyclic, or continuous, there are three times during the regeneration process that emissions can occur regardless of the regenerator type. These three emission points are: (1) the initial depressurization and purge vent; (2) the coke burn pressure control vent; and (3) the final catalyst purge vent.

The initial depressurization and purge cycle removes the hydrocarbons from the catalyst prior to CRU catalyst regeneration. The vent gases from this initial purge may have high levels of organic HAP such as benzene, toluene, xylene, and hexane.[10] This vent is typically vented to the refinery's fuel gas system or directly to a combustion device (e.g., flare or process heater).

The coke burn cycle is typically the largest (in terms of gas volume) emission source of the overall catalyst regeneration cycle. The primary HAP contained in the CRU coke burn vent are HCl and chlorine (Cl_2),[11] which are produced when the water formed during combustion leaches chloride atoms from the CRU catalyst. The CRU coke burn vent is typically a 3" to 6" pipe with a varying flow rate in the range of 50 to 1,000 scfm that is released to the atmosphere. The vent pipe may be only a few feet long, but may be longer to provide a release height of at least 15 to 20 feet. Caustic injection or caustic scrubbing may be used in the flue gas recirculation line to remove HCl. Although these HCl removal techniques are implemented primarily to protect the process equipment, they are also expected to reduce HCl emissions from the coke burn vent. Some systems operate a water or caustic scrubber for the vent line specifically to reduce HCl, although this is typically more common for continuous regenerators or cyclic systems that cycle frequently.

The final purge and reduction cycle removes oxygen and any remaining chorination agent from the system and reduces the catalyst prior to returning CRU catalyst to the reforming process or bringing the unit back on-line. The vent gases from this final purge may have low levels of the chlorinating agent (usually an organic HAP such as trichloroethene of perchloroethene) and residual HCl or Cl_2 remaining in the system.[10] This vent is typically vented to the atmosphere or the refinery's fuel gas system depending on the oxygen content of the vent gases (safety considerations restrict the venting of oxygen containing gases to the fuel gas system). Alternatively, the purge gas may be directly vented to a combustion device (e.g., flare or process heater).

Equipment leaks and fugitive process emissions may be significant for the chlorinated organic circulation system due to the high organic content of this stream. No other HAP emission points have been identified for the CRU or CRU catalyst regeneration process.

3.3 SULFUR RECOVERY PLANT

All crude oils contain some sulfur compound impurities. Crude oils that contain relatively low levels of sulfur are referred to as "sweet" crudes, while crudes that contain high levels of sulfur are referred to a "sour" crudes. Sulfur compounds are converted to hydrogen sulfide (H_2S) in the cracking and hydrotreating processes of the refinery. The H_2S or "acid gas" is removed from the process vapors using amine scrubbers. The amine scrubbing solution is subsequently heated to release the H_2S, and the acid gas is treated in the sulfur recovery plant to yield high purity sulfur that is then sold as product. The sulfur recovery plant consists of one or more sulfur recovery units (SRUs) operated in parallel and may also contain one or more catalytic tail gas treatment units and/or a thermal oxidizer (see Figure 3-6).

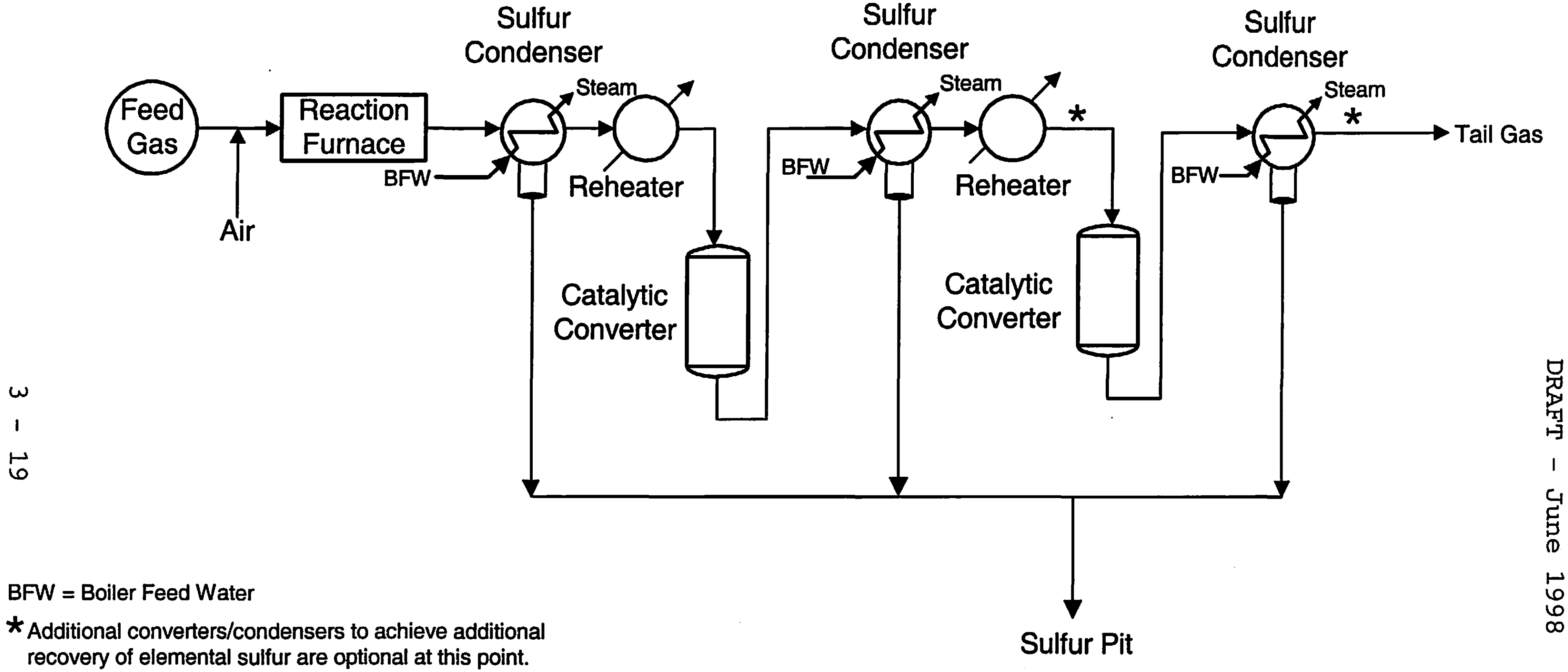
3.3.1 Claus Sulfur Recovery Unit (SRU) Process Description

Sulfur recovery (the conversion of H_2S to elemental sulfur) is typically accomplished using the modified-Claus process. This is a multi-stage catalytic oxidation of H_2S. First, one third of the H_2S is burned with air in a reaction furnace to yield sulfur dioxide (SO_2). The SO_2 then reacts reversibly with H_2S in the presence of a catalyst to produce elemental sulfur, water, and heat. Because the reaction is reversible, the reaction occurs in a series of reactors, and the vapors are cooled to condense the sulfur between each reactor to drive the reaction towards completion. Auxiliary burners are used to reheat the gas stream prior to the next reactor. The gas from the final condenser of the Claus unit (referred to as the "tail gas") consists primarily of inert gases with less than 2 percent sulfur compounds.

3.3.2 Tail Gas Treatment Unit (TGTU) Process Description

Tail gas treatment methods include any one or combination of: (1) catalytic reduction to convert as much of the tail gas sulfur compounds to H_2S (coupled with amine adsorption or Stretford solution eduction); (2) amine adsorption to recover and recycle any H_2S present in the tail gas; and (3) incineration to convert the remaining tail gas sulfur compounds to SO_2.

The most common tail gas catalytic reduction systems in use at refineries are: (1) the Shell® Claus Offgas Treatment (SCOT) unit; (2) the Beavon/amine system; (3) the Beavon/Stretford system; and (4) the Wellman-Lord system.



BFW = Boiler Feed Water

*Additional converters/condensers to achieve additional recovery of elemental sulfur are optional at this point.

Figure 3-6. Refinery MACT discussions: process vents Claus sulfur recovery units.

Except for the Wellman-Lord system, each of these systems consist of a catalytic reactor and an H_2S recovery system. In either the Claus or Beavon reactor, the tail gas is heated in the presence of hydrogen gas and a catalyst to reduce most of the tail gas sulfur compounds to H_2S. The off-gas from the catalytic reactor is typically quenched, then routed to an amine scrubber or a Stretford solution to strip the H_2S from the tail gas. The recovered H_2S is recycled to the front of the Claus unit. The overhead of the amine scrubber or Stretford unit (caustic scrubber) may be vented to the atmosphere or incinerated to convert any remaining H_2S or other reduced sulfur compounds to SO_2. The total sulfur recovery efficiency of a Claus/catalytic tail gas treatment train can be 99.5 percent or higher.

The Wellman-Lord uses thermal oxidation followed by scrubbing with a sodium sulfite and sodium bisulfite solution to remove SO_2. The rich bisulfite solution is sent to an evaporator-recrystallizer where the bisulfite decomposes to SO_2 and water and sodium sulfite is precipitated. Due to high capital, operating, and maintenance costs, the Wellman-Lord system is not widely used.[12]

3.3.3 Claus Sulfur Recovery Plant Emission Points

The primary emission point from the sulfur recovery plant is the final vent from the SRU, TGTU, or thermal oxidizer, whichever is the last process unit in the treatment train. There may be a separate emission stack for each SRU train; alternatively, the emissions from a couple of SRU trains may be combined, e.g., prior to thermal oxidation and release to the atmosphere. A typical SRU vent stack is approximately 4 feet in diameter and 100 feet tall. A typical volumetric flow rate for an SRU vent stack ranges from 8,000 to 40,000 scfm. The primary HAP components of the final sulfur plant vent are carbonyl sulfide (COS) and carbon disulfide (CS_2).[13] These HAP components are by-products of the SRU and TGTU reactions; COS may also be a product of incomplete combustion from a thermal oxidizer.

Sulfur recovery plants also have a potential for fugitive HAP emissions from the sulfur recovery pits. After each reactor in the SRU, elemental sulfur is condensed and removed from the SRU gas and the liquid sulfur is collected and stored in bins. There are limited data from a one petroleum refinery that suggest that small amounts of HAP are emitted from these sulfur recovery pits.[14]

There is also a potential for fugitive emissions from certain types of TGTUs, specifically the Stretford unit. The Stretford unit employs a series of open vessels as part of the solution circulation loop and a direct air contact cooling tower to cool the Stretford solution.[15] Limited data were reported that suggest that small amounts of HAP are emitted from these Stretford solution tanks.[16]

There are a few refineries that operate non-Claus type SRUs. All of the refineries that use non-Claus SRU technologies have very low sulfur production rates (2 long tons per day or less). There are several different trade names for these "other" types of SRU, such as the LowCat, Sulferox, and NaSH processes. In general, these processes operate at temperatures below 200°F and yield a sulfur product that has a much lower sulfur content (50 to 70 percent sulfur compared to 99.9 percent sulfur from the Claus process). There are no HAP emissions data from these other types of SRU. Industry representatives claim that these processes do not form COS and CS_2 while treating the sour gas, but these processes generally involve reactions specific for H_2S, and they will not otherwise remove any COS or CS_2 that may be present in the sour gas. That is, the non-Claus SRU are not expected to produce additional COS and CS_2, but they may potentially emit any COS or CS_2 that is present in the treated sour gas. As, these units represent much less than 1 percent of the total sulfur production capacity (or H_2S treatment capacity in the United States), the potential HAP emissions from non-Claus SRU are expected to be minimal compared to Claus SRU HAP emissions.

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4.0 CONTROL TECHNOLOGY AND PERFORMANCE OF CONTROLS

This chapter describes the control technologies applicable to reduce HAP emissions from the three petroleum refinery vents of interest (the CCUCR vent, the CRUCR vent and the sulfur recovery plant vent). It also presents a summary of the available performance data of the control technologies applicable for these three petroleum refinery vents.

4.1 CCUCR VENT EMISSION CONTROLS

There are two distinct types of emissions from CCUCR. These are: (1) metal HAP that are deposited on the catalyst particles; and (2) organic HAP are products of incomplete combustion. As such, there are two different types of emission control technologies considered for the CCUCR vent.

4.1.1 Metal HAP Emission Controls for the CCUCR Vent

As the metal HAP are associated primarily with the catalyst particles entrained in the CCUCR flue gas, particulate emission control devices also provide metal HAP emission control. To be applicable to the CCUCR flue gas, a particulate (metal HAP) emission control device must be able to treat large volumes of air continuously and reliably. As the CCU is often a critical process in a facility's refining efforts, any shutdowns of the process due to control device failure or maintenance must be minimized. There are four candidate particulate emission control devices that can handle continuous, large volumes of flue gas. These are: cyclone separators, electrostatic precipitators (ESPs), wet scrubbers, and fabric filters (baghouses).

Cyclone separators use centrifugal force to separate dust particles from gas streams. They have no moving parts, and they can continuously and reliably process large volume gas streams at the elevated temperatures typical of CCUCR flue gases. Cyclones are one of the least expensive dust collection devices in terms of both operating and capital investment costs, but they typically cannot meet the dust removal efficiencies of ESPs, baghouses, and wet scrubbers. Cyclones are generally applicable for dust particles with diameters greater than 5 µm, but multiple-tube parallel units may attain 80 to 85 percent collection efficiencies on 3 µm diameter particles.[1] Cyclone separators are used almost universally within the CCUCR units to retain most of the catalyst particles within the CCUCR unit. Second and third stage cyclones (i.e., cyclones in series) are commonly used external to the CCUCR unit for dust removal. By operating cyclones in series, dust collection efficiencies are reported to range from 90 to 98 percent.[2]

ESPs use an electrostatic field to charge dust particles within the gas stream. The charged particles migrate to a grounded collection surface where they adhere. The particles are then removed from the collection surface periodically by vibrating or "rapping" the collection surface. The dislodged particles are then collected in hoppers at the bottom on the ESP. ESPs typically have a high collection efficiency and can effectively remove particles with diameters of less than 1 µm.[3] ESPs can continuously and reliably process large volume gas streams at the elevated temperatures typical of CCUCR flue gases, and they are commonly used for particulate removal on the CCUCR vent gases.

Wet scrubbers use a liquid, usually water, to assist in the particle collection process. There are a number of different types of wet scrubbing process equipment,[4] but venturi type wet scrubbers are among the most efficient and the most commonly used at refineries for the CCUCR vent. Venturi wet scrubbers are typically designed for applications requiring very high removal efficiencies of particles ranging in diameter between 0.5 and 5 µm.[5] Venturi wet scrubbers may also provide some SO_x removal, but they have the disadvantage of generating a wastewater stream that requires treatment and/or disposal.

Baghouses use fabric filtration to remove dust particles from the gas stream. Baghouses are highly efficient, achieving removal efficiencies of greater than 99 percent for particles with diameters of 0.3 µm and greater.[6,7] However, baghouses are typically designed to operate at temperatures within 50 to 100 °F of the gas stream's dew point and generally cannot operate at temperatures above 500 °F.[8] Therefore, some pretreatment (or heat recovery) of the CCUCR flue gas will be required prior to a baghouse control device. Additionally, baghouses cannot provide continuous, long-term emission control due to maintenance problems (e.g., clogged or torn bags) according to air pollution control equipment representatives.[9]

Selection of an air pollution control device for TCCU is further complicated by the low operating pressure of the TCCU regenerator. Due to the pressure drops across the control device, installation of an ESP, wet scrubber or baghouse would require an induced draft fan to pull the CCUCR flue gas through the control device. The control of this induced draft fan would be critically tied to the process operations, making the application of these control devices impracticable. Single pass cyclone separators may be applicable and may yield sufficient control due to the larger size particles associated with the TCCU CCUCR vent. The TCCU surge tank vent is not limited by the control device pressure drop, but again, a cyclone separator may provide adequate control based on the particle size distribution of TCCU PM emissions.

Many refiners operate a catalytic hydrotreating unit and some of these refiners process a portion or all of the CCU crude oil feedstocks in these hydrotreaters prior to the CCU. The hydrotreater removes sulfur, nitrogen, vanadium, nickel and other contaminants from the crude oil feedstocks. This "pretreatment" step prior to the CCU typically helps to improve CCU yield, prolongs catalyst life, and reduces CCU HAP emissions, according to refinery representatives.[10] Due to the capital investment cost of hydrotreating units and their functionality for individual refineries, hydrotreating may not be a generally applicable emission reduction technique for all petroleum refineries. However, refiners that operate a hydrotreating unit and process a portion or all of the CCU feedstocks through the hydrotreater may exhibit reduced metal HAP emissions compared to a similarly operated CCU that does not hydrotreat the CCU feedstock.

4.1.2 Organic HAP Emission Controls for the CCUCR Vent

Organic HAP emissions primarily originate as by-products of coke combustion (e.g., formaldehyde, acetaldehyde, POM, dioxins and furans). However, volatile organic HAP such as benzene, toluene, xylenes, and hexane are also reported for some CCUCR vent streams.[11] These volatile organic HAP may originate as residual oil feed material on the catalysts that somehow vaporize, but do not combust prior to exiting the CCUCR. Presumably, these organic HAP emission would be greater for units that operate with insufficient oxygen (i.e., incomplete combustion CCUCRs). From the data available for organic emissions immediately following the CCUCR, it appears that incomplete combustion CCUCRs have significantly higher organic HAP emissions than complete combustion CCUCRs.[12]

Due to the large volumes and the low concentrations of organic HAP in the CCUCR flue gas, common organic HAP emission control devices such as condensers and carbon adsorption systems are not appropriate to control organic HAP emissions from the CCUCR vent. As the CCUCR flue gas is already at high (combustion) temperatures, catalytic incineration would not be economically competitive with traditional thermal incineration. Thus, thermal incineration or afterburning appear to be the only applicable air pollution control techniques to reduce organic emissions from the CCUCR flue gas.

Thermal incineration employs heat and oxygen to oxidize (combust) organic chemicals, converting them to carbon dioxide and water vapor at efficiencies of 99 percent or higher.[13,14] As the CCUCR flue gas stream is already at elevated temperatures, a minimum of auxiliary fuel would be required to achieve effective afterburning. Additionally, for incomplete combustion CCUCRs, the CO in the flue gas may be sufficient to fuel the secondary combustion process. Many incomplete CCUCRs already employ secondary combustion devices, typically referred to as CO boilers, to combust CO for the purpose of recovering the latent heat in the CCUCR flue gas. From the organic emission data available at the outlet of CO boilers and complete combustion CCUCRs, it appears that complete combustion CCUCRs can achieve comparable levels of organic HAP emission control as an incomplete combustion CCUCR followed by a secondary combustion unit.[15]

4.2 CRUCR VENT EMISSION CONTROLS

As described in Section 3.2.3, there are three times during the regeneration process that HAP emissions can occur. These three emission points are: (1) the initial depressurization and purge vent; (2) the coke burn pressure control vent; and (3) the final catalyst purge vent.

4.2.1 HAP Emission Controls for the CRU Purge Vent

The initial depressurization and purge cycle removes the hydrocarbons from the catalyst prior to CRU catalyst regeneration. The vent gases from this initial contains organic HAP such as benzene, toluene, xylene, and hexane. During the initial depressurization process, these hydrocarbons may be recovered by venting the gas stream to the refinery's fuel gas recovery system. As this vent gas stream hydrocarbon content becomes more dilute during the purge cycle, venting to the fuel gas system may become undesirable and an alternative air pollution control technique may de required. Air pollution control devices potentially applicable to this CRU purge vent stream include combustion devices such as a flare or vapor incinerator and carbon adsorption systems.

Flares and vapor incinerators employ heat and oxygen to oxidize (combust) organic chemicals, converting them to carbon dioxide and water vapor. Although destruction efficiencies of vapor incinerators may be slightly higher than flare systems, flare systems typically achieve destruction efficiencies of 98 percent or higher and they are more suitable for the intermittent flows typical of the CRU purge vent.[16]

Carbon adsorption may also be used to control organic HAP emissions during the CRU hydrocarbon purge cycle. Carbon adsorption systems remove organic chemicals from gas streams by selective adsorption onto the surface of activated carbon. There are two general types of carbon adsorption systems: regenerative and non-regenerative. Regenerative carbon systems offer an advantage over destructive emission control devices when the adsorbed organics can be economically desorbed and recovered. However, due to the low flow and intermittent nature of the CRU purge vent stream, non-regenerative (or canister) carbon adsorption systems are probably most economical for the CRU purge vent. When the adsorbed organics cannot be recovered or when non-regenerative carbon systems are used, carbon adsorption has the disadvantage of creating a solid waste material that requires proper disposal (sometimes as a hazardous waste).[17,18,19]

4.2.2 HAP Emission Controls for the CRUCR Coke Burn Vent

The primary HAP emitted during the coke burn cycle is HCl. Caustic injection, caustic scrubbing, and wet scrubbing are all applicable air pollution control techniques for removing HCl from the CRUCR coke burn flue gas. Wet scrubbers use a liquid, usually water, to effect removal of the desired pollutant. For vapor phase pollutants, scrubbing typically removes the pollutant by absorption into the liquid phase. Since HCl is readily soluble in water, wet scrubbing or absorption (with or without caustic addition) can achieve high HCl removal efficiencies (98 percent or higher).[20,21]

4.2.3 HAP Emission Controls for the CRUCR Final Purge Vent

The final purge and reduction cycle vent gases from may contain low levels of the chloriding agent (trichloroethene or perchloroethene) and residual HCl or Cl_2. Safety considerations (i.e., the presence of oxygen) may restrict the venting of the final purge cycle vent gases to the fuel gas system. However, the purge gases may be directly vented to a combustion device (e.g., flare, process heater, or incinerator), a carbon adsorption system, or a wet gas scrubber (absorption). Each of these types of air pollution techniques have been previously described in this section. If the primary HAP pollutants in the final CRUCR purge cycle are organics, then either combustion or carbon adsorption are most appropriate. If HCl or Cl_2 are the primary HAP from this vent at a given facility, then wet scrubbing is probably the most appropriate control device. The suitability of carbon adsorption may depend on the concentration of HCl in the vent stream because carbon has a low adsorption capacity for HCl and there is a potential for HCl condensation within the adsorption unit.[22] Application of thermal control devices may also be limited depending on the concentration of chlorine or chloride containing chemicals in the vent stream. Combustion of chlorinated organics produces HCl and provides the potential for the formation of chlorinated dioxins and furans.[23]

4.3 SULFUR PLANT VENT EMISSION CONTROLS

The primary HAP components of the final sulfur plant vent are carbonyl sulfide (COS) and carbon disulfide (CS_2). These HAP components are by-products of the reactions in the SRU reactors; COS may also be a product of incomplete combustion from a thermal oxidizer. There are two generally applicable emission control techniques for the SRU vent.

These are either the use a TGTU or a thermal oxidizer (or both).

4.3.1 TGTU as a HAP Emission Control for the SRU Vent

By recovering sulfur from the SRU tail gas, TGTUs are expected to reduce the concentration of sulfur containing compounds (HAP) in the sulfur plant vent as compared to a similar SRUs with no TGTU. Different types of TGTUs were described in Section 3.3.3. A typical TGTU recovers approximately 95 percent of the sulfur remaining in the SRU tail gas (i.e., a combined SRU/TGTU sulfur recovery efficiency of over 99.5 percent).[24] At this time, the EPA has insufficient data to determine if the sulfur recovery efficiency of a TGTU is directly correlated to its HAP emission reduction or whether a given TGTU provides greater HAP emission reduction than any other TGTU. It appears that certain TGTUs may have a higher potential for secondary (fugitive) emissions due to the type of TGTU process used (e.g., Stretford units may have secondary emissions from the handling and storage of the Stretford eduction solution).

Thermal and catalytic oxidizers or combustion units are also applicable air emission control devices to reduce the HAP emissions from the sulfur plants. Thermal and catalytic oxidizers convert (combust) reduced sulfur compounds to sulfur oxides (SO_x). Thermal and catalytic oxidizers may be applicable for nearly all SRU vents regardless of the presence or absence of a TGTU (although they may not be appropriate following an oxidative TGTU process such as a Wellman-Lord TGTU). The destruction or oxidation efficiency of reduced sulfur compounds, including COS and CS_2, in a properly designed and operated thermal or catalytic oxidizer is anticipated to be 99 percent or higher.[25]

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5.0 MODEL PLANTS AND EMISSION ESTIMATES

This chapter presents the derivation of controlled and uncontrolled emission factors for hazardous air pollutants (HAP) and applies them to three different sizes of model plants to provide an estimate of the potential level of emissions on a plant basis. In addition, the emission factors are applied on a nationwide basis to estimate controlled and uncontrolled emissions from the entire industry for the three processes of interest: catalytic cracking unit (CCU) regeneration, catalytic reforming unit (CRU) regeneration, and sulfur recovery units (SRUs).

5.1 MODEL PLANTS

The three model plants used to represent small, medium, and large facilities for the purpose of presenting typical levels of emissions are given below.

No.	Size	Model plant capacities			
		Crude oil (bbl/day)	Catalytic cracking (bbl/day)	Catalytic reforming (bbl/day)	Sulfur recovery (ltons/d)
1	Small	25,000	8,300	6,300	30
2	Medium	75,000	25,000	19,000	120
3	Large	200,000	70,000	50,000	480

bbl = barrels

5.2 HAP EMISSIONS FROM CCU REGENERATION

Data for HAP emissions were compiled by the EPA using information provided through a variety of sources and are documented in References 1 and 2. A summary of the emissions data is given in Appendix B. The emissions data were reported in responses to information collection requests and follow-up surveys by the American Petroleum Institute (API) the National Petroleum Refiners Association (NPRA), as well as collected during site visits conducted by EPA. The approach used to estimate HAP emissions in this section attempts to provide a range of "best estimates" rather than an extreme range based on the absolute highest and lowest values reported. Estimates are provided only for those compounds that were actually detected and quantified. The original data base contained several entries for pollutants that were not detected, and the detection limits were reported and included with other information based on actual measured values.

The analysis of HAP emissions from CCU regeneration is based on the following approach:

1. Estimates are not provided for pollutants that were **not detected**, even when they are reported in the survey results at the detection limits. In addition, if there was only one facility that reported the presence of a specific compound that was not verified by any other information, that value was flagged and was not used in the estimates of total HAP emissions.

2. When the extremes of the range for a given pollutant differ by **an order of magnitude or more** from the bulk of the data, the extreme high and/or low values are not used to estimate a representative range of emissions (i.e., these values are treated as outliers). However, the tables clearly note when an extremely high or low value is not used in the analysis.

3. The data for CCU regeneration were mostly for units that **controlled emissions** with the destruction of organic compounds in a carbon monoxide (CO) boiler and control of particulate matter by cyclones and an electrostatic precipitator (ESP). Because of the combustion process, it is difficult to determine if the measurements made after the CO boiler represent products of incomplete combustion and/or by-products or if they represent the residual of compounds that were

not completely destroyed. For example, formaldehyde, acetaldehyde, and polycyclic organic matter (POM) may actually be formed in the CO boiler as by-products of combustion or they may be present before combustion in larger quantities. For this analysis, the data for organic HAP (generally after the CO boiler) are used to derive emission factors for controlled organic HAP emissions. Uncontrolled organic HAP emissions are estimated based on a assumption that the controlled emission factors represent 98 percent destruction (i.e., the uncontrolled emission factors are assumed to be 50 times the controlled emission factors). This emission factor is applied <u>only to units using partial combustion that do not vent to a CO boiler or other combustion device</u>. For complete combustion units, emissions of organic HAP are estimated from the "controlled" emission factors.

4. Estimates of **uncontrolled emissions** of HAP metals for CCU regeneration are based on the measurements after the control device and the assumption of a nominal control efficiency of 95 percent for the ESP.

5. Based on a review of the data, no distinction could be made in emission factors for CCUs using partial combustion and those using complete combustion. A significant difference would be expected in the **uncontrolled** emissions from the two different types of combustion processes; however, the difference in organic compound emissions may be much less after combustion in a CO boiler. In addition, 32 of the 34 CCUs using partial combustion in the current data base were identified as having controls (e.g., CO boiler), and only 2 were identified as having no controls. Consequently, uncontrolled emission factors for partial combustion processes may not be important in determining nationwide emissions.

6. The data were inconclusive as to whether **hydrotreating** had any effect on the emission factors for HAP metals; consequently, this analysis uses the same emission factors for units that hydrotreat as for those that do not.

The range of controlled emission factors for organic HAP derived from the data in Appendix B is given in Table 5-1 and the range for controlled metal HAP and HCl is given in Table 5-2. Both are expressed in terms of pounds of emissions per million barrels of CCU throughput (lb/mm bbl). Nickel was the most commonly reported metal HAP and was also the one reported in the highest quantities. The range and midrange for the emission factors are given in Table 5-3.

Using the approach and assumptions discussed above, these factors were applied to the model plants to estimate uncontrolled and controlled emissions. The results are given in Table 5-4 for the sum of organic, metal HAP, and HCl. The results for the model plants indicate that the units with particulate matter controls probably have metal HAP emissions that total less than a ton per year.

Nationwide emission estimates for CCU regeneration were derived based on CCU capacity and control devices in place. Based on data from API[3], information on emission controls was available for plants with 4.5 million bbl/day of CCU capacity out of a total nationwide capacity of 5.2 million bbl/day. Approximately 27 percent of the nationwide capacity did not have control devices in place for PM (1,400,000 bbl/day). In addition, only 47,000 bbl/day of the total capacity was projected to have no controls for emissions of organic compounds (i.e., uncontrolled units using partial combustion). Nationwide emission estimates are given in Table 5-5 for the baseline (current level of control) and for the "controlled" case, which assumes that all units control metal HAP and organic HAP.

TABLE 5-1. SUMMARY OF ORGANIC HAP DATA FROM CCU REGENERATION (from References 1 and 2)

Compound	Emission factor range (lb/mm bbl)[1]		Number[2]	Comments
	Lower	Upper		
1,3-Butadiene	0.0008	0.05	2	all after CO boiler
Acetaldehyde	1.7	48	6	after CO boiler
Benzene	0.73	12	5	after CO boiler
Cyanide	28	36	2	all after CO boiler
Formaldehyde	2.7	950	7	after CO boiler, excludes two very high values
HCN	14	194	5	with and without CO boiler, excludes one high and one low value
Phenol	0.74	41	5	with and without CO boiler
POM[3]	0.15	3	2-5	most after CO boiler and ESP
Toluene	0.26	2.5	2	all after CO boiler; excludes one very high value
Xylene	3.2	3.2	1	after CO boiler
PCDF[4]	5.5e-07	5.5e-07	1	after CO boiler and ESP
HCDF[5]	1.1e-06	1.1e-06	1	after CO boiler and ESP
Total VOCs[6]	78	1,240	9	after CO boiler or complete combustion CCUCR
Totals	**51**	**1,290**		

[1] lb/mm bbl = pounds per million barrels.
[2] Number of facilities reporting detectable quantities of the compound.
[3] POM = polycyclic organic matter determined from the sum of individual compounds in Appendix B.
[4] Total pentachlorodibenzofuran.
[5] Total hexacholordibenzofuran.
[6] Total volatile organic compounds (as reported in Ref. 2; not included in HAP totals).

TABLE 5-2. SUMMARY OF CONTROLLED METAL HAP EMISSIONS AND HCl DATA FROM CCU REGENERATION (from References 1 and 2)

Compound	Emission factor range (lb/mm bbl)[a]		Number[b]
Antimony	0.0032	10.0	8
Arsenic	0.0010	1.7	8
Beryllium	0.0020	0.1	5
Cadmium	0.0040	2.8	8
Chromium	0.0430	15.2	12
Cobalt	0.0075	1.5	6
Lead	0.1100	8.2	10
Manganese	0.1400	19.7	9
Mercury	0.0010	0.6	8
Nickel	0.0022	43.0	21
Selenium	0.0062	29.4	8
Totals	**0.32**	**132**	
HCl	528	2,300	2

[a] lb/mm bbl = pounds per million barrels.
[b] Number of facilities reporting detectable quantities.

TABLE 5-3. SUMMARY OF HAP EMISSION FACTORS FOR CCU REGENERATION

HAP and type of control	Emission factor range (lb/mm bbl)[1]		
	Lower	Upper	Midrange
Total organics-controlled	51	1,290	670
Total organics-uncontrolled[a]	2,550	64,500	33,500
Metal HAP-controlled	0.32	132	66
Metal HAP-uncontrolled[b]	6	2,640	1,320
HCl	528	2,300	1,400

[a] Assumes controlled emissions represent 98 percent destruction; applied only to uncontrolled partial combustion units.
[b] Assumes controlled emissions represent 95 percent removal.

TABLE 5-4. SUMMARY OF RANGE OF POTENTIAL HAP EMISSIONS FOR CCU REGENERATION FROM THE MODEL PLANTS

Model plant	1	2	3
Capacity (bbl/day)	8,300	25,000	70,000
Total organic-uncontrolled partial combustion (tpy)[a]	3.9 - 98	12 - 294	33 - 820
Total organic-controlled (tpy)	0.08 - 2.0	0.23 - 5.9	0.65 - 16
Total metal-uncontrolled (tpy)[b]	0.01 - 4.0	0.03 - 12	0.08 - 34
Total metal-controlled (tpy)	0.0005 - 0.2	0.001 - 0.6	0.004 - 1.7
HCl	0.8 - 3.5	2.4 - 10.5	6.7 - 29

bbl/day = barrels per day.
tpy = tons per year.

[a] Applied only to partial combustion units that do not vent to a CO boiler or other combustion device.

[b] The vast majority of the larger units use a PM control. Consequently, these estimates are probably most relevant for CCUs in the size range of Model Plants 1 and 2.

TABLE 5-5. SUMMARY OF NATIONWIDE EMISSIONS ESTIMATES FOR CCU REGENERATION

Case	Range	Metal HAP (tpy)[a]	Organic HAP (tpy)[b]
Baseline	Lower	1.8	70
	Upper	770	1,800
	Midrange	380	920
Controlled[c]	Lower	0.3	48
	Upper	120	1,200
	Midrange	62	630

[a] Based on the emission factors in Table 5-3, an uncontrolled capacity of 1,400,000 bbl/day, and a controlled capacity of 3,780,000 bbl/day.

[b] Based on the emission factors in Table 5-3, an uncontrolled capacity of 47,000 bbl/day, and a controlled capacity of 5,133,000 bbl/day.

[c] Based on the emission factors in Table 5-3 and a controlled capacity of 5,180,000 bbl/day.

5.3 HAP EMISSIONS FROM CRU REGENERATION

The data available for HAP emissions from CRU regeneration were compiled by EPA (References 1 and 2) and are presented in Appendix B. Additionally, data from one emission source test was available to estimate emission factors for dibenzofurans both before and after a temporary carbon adsorption control device (Reference 4). The emission factors developed for CRU regeneration are summarized in Table 5-6. There were very limited emission data for nearly all HAP except chlorine (Cl_2) and hydrogen chloride (HCl) from uncontrolled CRU. Additionally, nearly all of the Cl_2 and HCl emission data are from continuous or cyclic CRU catalyst regeneration. Therefore, a **single emission factor** was developed and applied to all CRU regardless of the type of regeneration employed, whether **cyclic, continuous, or semi-regenerative**.

Most of the data for benzene, toluene, and xylene were from measurements after combustion in a process heater, and information supplied by the industry indicated that organic emissions are typically controlled by venting to a combustion device. A range of 23 to 28 lb per million barrels was developed to represent emissions of organic HAP from CRU regeneration following combustion. No "uncontrolled" emission factor was developed for organics from CRU catalyst regeneration.

There are two sets of data regarding the emissions of HAP metals during CRU regeneration. Although these two sets of data yielded metal HAP emission factors that varied by four orders of magnitude, even the upper range emission factor was very low. Applying the upper range metal HAP emission factor for the largest model plant CRU yields emissions of only 1 lb/yr. Based on these limited and disparate metal HAP emission data, it was appears that metal HAP emissions from CRU is either negligible or non-existent.

Data were available for chlorine and HCl both before and after control, although most of the data represented uncontrolled emissions. Comparing the emissions range for controlled versus uncontrolled emissions, it appears that a control efficiency of approximately 99 percent may be achieved. However, based on an evaluation of the available process data, the level of HCl scrubber control devices in-place at semi-regenerative CRU are significantly different than those in-place at continuous and cyclic CRU units. Therefore, the midrange value of 4,450 lb/million barrels was used to estimate uncontrolled emissions and the emission factors for controlled units were then calculated using this uncontrolled emission factor and the nominal emission control efficiency for the specified level of HCl scrubber control(either 92 or 97 percent).

The emission factors for CRU regeneration are summarized in Table 5-7. These factors were applied to the model plants in Table 5-8 to estimate typical plant emissions. The results in Table 5-8 show that controlled emissions of all HAP from CRU regeneration total at or less than a ton per year for the midrange CRU and total between 1 and 3 tons per year for large CRU.

The major HAP from uncontrolled CRU regeneration is **HCl**, which was reported by numerous facilities at rates comparable to the upper end of the range shown for the model plants. Due to the different level of HCl scrubber control devices in-place at semi-regenerative CRU compared to those in-place at continuous and cyclic CRU units, separate estimates are provided for semi-regenerative CRU and continuous/cyclic CRU in developing the nationwide estimates of emissions from CRU regeneration. From the available process data, semi-regenerative CRU processed 1.63-million barrels per day of feedstock; 73 percent of that throughput is controlled by single-stage (assumed 92 percent efficient) scrubbers and 4 percent is controlled by multiple-stage (assumed 97 percent efficient) scrubbers. Cyclic and continuous reformers combined processed 2.02-million barrels per day of feedstock and 38 percent of that throughput is controlled by multiple-stage scrubbers, with only 6 percent controlled by single-stage scrubbers. The nationwide estimates of baseline and controlled emissions from CRU regeneration are summarized in Table 5-9. The estimates for controlled emissions assume that all uncontrolled semi-regenerative CRU regeneration vents are equipped with single-stage scrubbers to remove HCl at an efficiency of 92 percent, and all continuous and cyclic CRU regeneration vents are equipped with multiple-stage scrubbers to remove HCl at an efficiency of 97 percent.

TABLE 5-6. SUMMARY OF HAP DATA FROM CRU REGENERATION (from References 1 and 2)

Compound	Emission factor range (lb/mm bbl)[a]		Number[b]	Comments
Benzene	1.5	6.5	3	After control
Toluene	9.6	9.6	1	After control
Xylene	7.0	7.0	1	After control
PAH[c]	4.5	4.5	1	After control
Dibenzofurans				
Tetrachloro	2.8 E-09	8.4 E-09	1	(d)
Pentachloro	4.5 E-09	1.6 E-08	1	(d)
Hexachloro	7.4 E-09	2.4 E-08	1	(d)
Heptachloro	BDL	1.4 E-08	1	(d)
Octachloro	BDL	3.1 E-09	1	(d)
Total	1.5 E-08	9.3 E-08	1	(d)
Total organic	**23**	**28**		**After control**
Chlorine	0.26	0.26	1	After control
HCl	0.06	4.0	2	After control
Total Cl HAP	**0.32**	**4.3**		**After control**
Chlorine	0.44	440	10	Uncontrolled
HCl	34	8,430	20	Uncontrolled
Total Cl HAP	**34**	**8,870**		**Uncontrolled**

[a] lb/mm bbl = pounds per million barrels.

[b] Number of facilities reporting detectable quantities.

[c] PAH = polycyclic aromatic hydrocarbons, which include POM.

[d] Left hand column represents emissions after temporary carbon adsorber, right hand column represents emissions before control device. Assumes 90 hours of coke burn-off per year.

TABLE 5-7. SUMMARY OF HAP EMISSION FACTORS FOR CRU REGENERATION

HAP and type of control	Emission factor range (lb/mm bbl)[1]		
	Lower	Upper	Midrange
Total organics[a]	23	28	25
Cl[b] HAP-uncontrolled	34	8,870	4,450
Cl HAP-controlled	--	--	130-360[c]

[a] Based on venting to a combustion device.
[b] Includes HCl and chlorine.
[c] Controlled emission factor range calculated based on uncontrolled emission factor assuming a 92 to 97 percent removal efficiency.

TABLE 5-8. CRU HAP EMISSION ESTIMATES FOR MODEL PLANTS

Model plant	1	2	3
Capacity (bbl/day)	6,300	19,000	50,000
Organics(tpy)	0.026 - 0.032	0.08 - 0.10	0.21 - 0.26
Cl HAP-uncontrolled (tpy)	5.1	15	40
Cl HAP-controlled (tpy)	0.2 - 0.4	0.5 - 1.2	1.2 - 3.2

bbl/day = barrels per day.
tpy = tons per year.
lb/yr = pounds per year.

TABLE 5-9. NATIONWIDE HAP EMISSION ESTIMATES FOR CRU REGENERATION

Condition	HAP	Emissions (tpy)
Baseline[a]	Organics	15 - 19
	HCl and Cl_2	1,350
Controlled[b]	Organics	15 - 19
	HCl and Cl_2	150

[a] Baseline estimates for HCl and Cl_2 are based on 1,306,000 bbl/day of capacity with single stage scrubbers, 814,000 bbl/day of capacity with multiple stage scrubbers and 1,529,000 bbl/day of capacity without scrubbers.

[b] Controlled estimates assume 1,577,000 bbl/day of capacity is equipped with single stage scrubbers and 2,072,000 bbl/day of capacity is equipped with multiple stage scrubbers.

5.4 HAP EMISSIONS FROM SULFUR RECOVERY UNITS (SRUs)

The major HAP from sulfur recovery units are carbon disulfide (CS_2) and carbonyl sulfide (COS). The data for these compounds are summarized in Table 5-10 and were obtained primarily from responses to section 114 requests.[5,6] (See Appendix B for more details.) These data represent HAP emissions following the incinerator and show a range of 29 to 285 lb per 1,000 long tons per day (ltpd) of sulfur production capacity. To estimate potential emissions from units that do not have an incinerator, a destruction efficiency of 98 percent was assumed, which yields an uncontrolled emission factor of 1,450 to 14,250 lb/1,000 ltpd.

These emission factors were applied to the model plants in Table 5-11 to estimate typical plant emissions. Nationwide emission estimates are based on survey data provided by NPRA.[6] The SRU database contains capacity information on 161 units nationwide with a total sulfur pruduction capacity of 18,880 ltpd. The database contains process type and control information for 140 SRU and 120 of these units were identified as having an incinerator (or were subject to the NSPS for SRUs). The capacity of these controlled units was estimated as 15,470 ltpd, and the capacity of units without incinerators was estimated as 3,410 ltpd. These capacity estimates were used with the emission factors to estimate nationwide emissions in Table 5-11.

TABLE 5-10. SUMMARY OF HAP EMISSIONS DATA FOR SRU VENTS [7,8]

Plant ID	HAP	Emissions (lb/1,000 ltpd)
20501	CS_2	29
20701	COS	285
20604	COS	171
G	COS	50
F	COS, CS_2	180
Range		29 - 285

TABLE 5-11. HAP EMISSION ESTIMATES FOR SRU VENTS (COS and CS_2)

	Model plants		
Size (ltpd)	30	120	480
Uncontrolled (tpy)	7.9 - 78	32 - 310	130 - 1,250
Controlled (tpy)	0.16 - 1.6	0.6 - 6.0	2.5 - 25
	Nationwide[1]		
Baseline (tpy)		980 - 9,700	
Controlled (tpy)		100 - 1,000	

[1] Nationwide estimates based 15,470 ltpd of sulfur produced in controlled units and 3,410 ltpd of sulfur produced in uncontrolled units.

5.5 REFERENCES

1. Letter from David Hansell, EER, to Robert Lucas, U.S.EPA, transmitting the API CCU and CRU Data Base Summary (Draft). December 20, 1996.

2. Letter from David Hansell, EER, to Robert Lucas, U.S.EPA, transmitting the Detailed API CCU and CRU Data Base (2nd Draft). January 23, 1997.

3. Database spreadsheet provided by David Hansell, EER, to Robert Lucas, U.S.EPA, updating the API database, April 1997.

4. Radian Corporation. Results of Dioxin Testing on the Catalytic Reformer Unit #1 Exhaust; Texaco Refinery; Bakersfield, California. Final Report. August 8, 1991.

5. U.S Environmental Protection Agency. Responses to Information Collection Request for Petroleum Refineries. Office of Air Quality Planning and Standards, Research Triangle Park, NC. 1992.

7. U.S. Environmental Protection Agency. Presumptive MACT for Petroleum Refinery Process Vents: FCC Units, Reformers, and Sulfur Recovery Plants. Appendix B-Summary of Emissions Data. Office of Air Quality Planning and Standards, Research Triangle Park, NC. 1997.

8. Letter from Norbert Dee, NPRA, to Robert Lucas, U.S.EPA, transmitting SRU Database. June 12, 1997.

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6.0 OTHER ENVIRONMENTAL AND ENERGY IMPACTS ESTIMATES

This chapter presents estimates the environmental impacts, other than HAP emission reduction, and the energy impacts associated with the control technologies applicable for the three petroleum refinery process vents. Many of the other environmental and energy impact estimates are based on control device design algorithms from EPA's Control Cost Manual.[1] The control equipment design parameters are, therefore, summarized in Chapter 8 of this document and only the applicable environmental and energy impacts are provided in this chapter. For more details on the control device design parameters, the reader is referred to Chapter 8.

6.1 OTHER ENVIRONMENTAL IMPACTS FOR CCUCR VENTS

The primary impacts from the operation of ESPs to control metal HAP emissions from the CCUCR vent are the added energy requirements of the ESP and the exhaust fan. These energy requirements were estimated based on the control device designs for model CCUCR units as described in Chapter 8. The ESP will also collect particle fines from the CCU vent stream that will require disposal as a non-hazardous solid waste. The quantity of CCU fines requiring disposal was calculated in the costing algorithm from the particle loading to the ESP.

There are two additional considerations in estimating the other environmental impacts of operating a wet scrubber emission control device for the CCUCR vent. First, the wet scrubber also creates a wastewater stream which contains the CCU fines. It is assumed that the CCU fines are first settled (removed) from the wastewater stream and that the wastewater stream then requires additional treatment and disposal. The costing algorithm assumes that the total weight of the settled solids is 2 times the particle loading to the wet scrubber. The amount of water requiring treatment and disposal is also estimated from the control cost algorithms.

The second consideration in estimating the other environmental impacts of operating a wet scrubber emission control device is the scrubbers ability to also remove sulfur oxides (SO_x, which includes both SO_2 and SO_3). The amount of SO_x in the CCUCR flue gas is dependent primarily on the sulfur content of the CCU feedstock. For the purposes of estimating other environmental impacts, it is assumed that the average SO_x concentration in the CCUCR flue gas is 500 ppmv (450 ppmv SO_2 and 50 ppmv SO_3) and it is assumed that the scrubber's SO_x removal efficiency is 90 percent.[2]

Table 6-1 provides a comparison of the other environmental and energy impact estimates for an ESP and a wet scrubber control device used to remove metal HAP for the model CCUCR units.

Due to the relatively high CO content of incomplete combustion CCUCR exhaust gases, energy may actually be recovered using a combustion device on this vent stream. Additionally, refineries may be expected to have additional fuel gas that could be used to stabilize the incinerator flame. However, it is assumed that energy is not being recovered from the CCUCR vent incinerator except for heat recovery as specified in the control cost's incinerator design and that natural gas is used to stabilize the incinerator flame for the purposes of estimating other environmental and energy impacts. The incinerator uses both electricity (for the exhaust fan) and natural gas. Table 6-2 summarizes the other environmental and energy

TABLE 6-1. COMPARISON OF OTHER ENVIRONMENTAL AND ENERGY IMPACTS FOR INORGANIC HAP EMISSION CONTROL DEVICES FOR THE CCUCR VENT.

Control Device/ Annual Impact	**Small CCU**		**Medium CCU**		**Large CCU**	
	w/o CO Boiler	**w/ CO Boiler**	**w/o CO Boiler**	**w/ CO Boiler**	**w/o CO Boiler**	**w/ CO Boiler**
ESP						
Electricity Use (1,000 kW-hr)	470	630	1,730	2,200	4,400	6,290
Solid Waste (tons)	180	240	680	860	1,710	2,450
Venturi Scrubber						
Electricity Use (1,000 kW-hr)	390	520	1,420	1,810	3,620	5,170
Solid Waste (tons)	370	490	1,350	1,720	3,430	4,910
Water Consumption (1E+06 gallons)	130	170	470	600	1,200	1,720
SO_x Emissions[1] (tons)	(300)	(400)	(1,100)	(1,400)	(2,800)	(4,000)

[1] Brackets around other emission impact estimates indicate emission reductions.

TABLE 6-2. ANNUAL OTHER ENVIRONMENTAL AND ENERGY IMPACT ESTIMATES FOR MODEL CCUCR VENT INCINERATORS.

Annual Impact	**Small CCU**	**Medium CCU**	**Large CCU**
Electricity Use (1,000 kW-hr)	600	2,190	5,580
Natural Gas Consumption (1E+06 cubic feet)	31	114	290

impacts for a thermal incinerator used to destroy organic HAP in the CCUCR vent model units.

Nationwide estimates of other environmental and energy impacts were developed using the throughput of units anticipated to add control devices for CCU units(i.e., the same assumptions used to estimate the emission reductions presented in Chapter 5). The other environmental and energy impacts were estimated two separate ways based on the type of inorganic HAP emission control device installed. The first analysis assumes all units install an ESP; the second analysis assumes all units install a venturi scrubber. The nationwide impacts estimates for both these analyses are presented in Table 6-3.

6.2 OTHER ENVIRONMENTAL IMPACTS FOR CRUCR VENTS

The types of other environmental and energy impacts associated with wet scrubbing to remove HCl from the CRUCR vent stream include electricity use for fans and pumps and the production of a wastewater stream that requires treatment and disposal. These impacts are directly estimated from the control cost algorithms for the model CRUCR units as described in Chapter 8. The other environmental and energy impacts estimates for the CRU vent model units are summarized in Table 6-4; the nationwide other environmental and energy impacts estimates for the CRUCR units are provided in Table 6-5.

TABLE 6-3. NATIONWIDE ANNUAL OTHER ENVIRONMENTAL AND ENERGY IMPACTS ESTIMATES FOR THE CCUCR VENT[1]

Nationwide Annual Impact	**ESP/ Incinerator**	**Venturi Scrubber/ Incinerator**
Electricity Use (1E+06 kW-hr)	100	87
Solid Waste (tons)	41,200	82,500
Wastewater Production (1E+06 gallons)	0	28,900
SO_x Emissions(tons)	0	(67,200)[2]
Natural Gas Consumption (1E+06 cubic feet)	31	31

[1] Based on adding an inorganic HAP control device (either an ESP or a venturi scrubber) for 1,400,000 bbl/day of CCU capacity and adding an organic HAP control device (incinerator) for 47,000 bbl/day capacity.

[2] Brackets around emission impact indicate an emission reduction.

TABLE 6-4. OTHER ENVIRONMENTAL AND ENERGY IMPACTS ESTIMATES FOR MODEL PLANT CRUCR VENTS

No.	**CRUCR Type**	**CRU Throughput Range (1,000 bpd)**	**Annual Electricity Use (kW-hr)**	**Annual Wastewater Production (1,000 gal)**
1	Semi-Regen.	0 to <15	349	39
2	Semi-Regen.	15 to 30	621	70
3	Semi-Regen.	>30	1,160	130
4	Cyclic	0 to <15	1,360	57
5	Cyclic	15 to 30	2,270	95
6	Cyclic	>30	4,090	170
7	Continuous	0 to <15	1,230	51
8	Continuous	15 to 30	2,050	86
9	Continuous	>30	4,090	170

TABLE 6-5. NATIONWIDE ANNUAL OTHER ENVIRONMENTAL AND ENERGY IMPACTS ESTIMATES FOR THE CRUCR VENT[1]

CRUCR Type	**Annual Electricity Use (kW-hr)**	**Annual Wastewater Production (1,000 gal)**
Semi-Regenerative	13,000	1,460
Cyclic/Continuous	113,000	4,750
Total	126,000	6,210

[1] Based on facility specific analysis of size and type of CRUCR using impact factors presented in Table 6-4. Total throughput of CRU units adding controls was 1,529,000 bbl/day.

6.3 OTHER ENVIRONMENTAL IMPACTS FOR SRU VENTS

The environmental and energy impacts associated with the SRU vent emission controls include both electricity and natural gas consumption as well as additional SO_x emissions due to the conversion of reduced sulfur compounds to SO_x.

The energy impacts are directly estimated from the control cost design algorithms for the model SRU incinerators as described in Chapter 8. The SO_x emissions estimates are based on the reduced sulfur compound inlet concentration of 4,000 ppmv (as used in the incinerator design) and one mole SO_x produced per mole of reduced sulfur compound in incinerator inlet. Table 6-6 summarizes the other environmental and energy impacts estimates for model SRU units. Table 6-7 presents the nationwide other environmental and energy impacts estimates for SRU vents.

TABLE 6-6. ANNUAL OTHER ENVIRONMENTAL AND ENERGY IMPACT ESTIMATES FOR MODEL SRU VENT INCINERATORS.

Annual Impact	**Small CCU**	**Medium CCU**	**Large CCU**
Electricity Use (1,000 kW-hr)	135	539	2,160
Natural Gas Consumption (1E+06 cubic feet)	11	44	178
SO_x Emissions(tons)	336	1,340	5,380

TABLE 6-7. NATIONWIDE OTHER ENVIRONMENTAL AND ENERGY IMPACT ESTIMATES FOR SRU VENTS[1]

Annual Impact	**Nationwide**
Electricity Use (1,000 kW-hr)	2,160
Natural Gas Consumption (1E+06 cubic feet)	178
SO_x Emissions(tons)	38,200

[1] Based on incinerators added to control emissions from the production 3,410 ltpd of sulfur.

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7.0 MONITORING OPTIONS

This chapter presents a brief review of options available for monitoring HAP emission at petroleum refineries for each process vent (CCUCR, CRUCR, SRU vents). In general, the monitoring options were established using the following priorities. The top priority was given to the use of continuous emission monitors (CEMs) that directly measure HAP emissions. Second priority was given the continuous emission monitors that measure a surrogate of HAP emissions (such as particulate matter for metal HAP). Third priority was given to continuous monitoring of process parameters that are indicative of process emissions or the effectiveness of the emission control device.

7.1 MONITORING OPTIONS FOR THE CCUCR VENT

There are two separate monitoring options for the CCUCR vent based on the two classes of HAP/control devices. For organic HAP, continuous emission monitoring for specific organic HAP was not considered a proven (commercially available and reliable) monitoring option at this time, and was considered inferior to other continuous monitoring options due to the time delay between sample collection and the availability of final results. Continuous monitoring of an indicator of organic HAP was therefore evaluated. Two potential indicators of organic HAP were considered. These were: 1) continuous monitor of total hydrocarbon (THC) or total organic carbon (TOC) using a flame ionization detector (FID) or a photo ionization detector CEM; and 2) continuous monitoring of carbon monoxide (CO) using a carbon monoxide CEM. Both of these monitoring devices appear feasible for the CCUCR vent. Several refineries currently employ continuous TOC or CO monitors; however, only CO CEMs are employed specifically on the CCUCR vent (to show compliance with the petroleum refinery NSPS - 40 CFR 60, Subpart J).[1] As the available emission data show an equally strong correlation between measured organic HAP and CO emissions as they do organic HAP and THC/TOC emissions, a continuous CO monitor was selected as the surrogate CEM for further evaluation. Finally, parametric monitoring options were considered. For complete combustion CCUCR units, continuous parametric monitoring of temperature and exhaust oxygen content were selected as a monitoring option to indicate complete combustion of organic HAP. For CO boilers/thermal incinerators used for incomplete combustion CCUCR units, continuous parametric monitoring of temperature was selected as a monitoring option to indicate proper incinerator performance and operation. These parameters are commonly monitored at nearly all CCUCR units.

Continuous emission monitoring of either metal HAP or an indicator of metal HAP such as particulate matter (PM) was not considered proven (commercially available and reliable) CEM. Additionally, the lag time between sampling and analysis for these monitoring approaches makes them inferior to continuous parametric monitoring of the control device. The appropriate parameters to monitor are dependent on the control device used to achieve. For ESPs, continuous parametric monitoring of voltage and secondary current were selected as a monitoring option to indicate proper control device performance and operation. For venturi wet scrubbers, continuous parametric monitoring of pressure drop, air flow rate, and water flow rate were selected as a monitoring option to indicate proper wet scrubber performance and operation.

7.2 MONITORING OPTIONS FOR THE CRUCR VENT

For the depressurization/purge and the rejuvenation/ final purge CRUCR vents, the vent gases are either vented to the refineries fuel gas (flare) system or a dedicated thermal combustion device. The monitoring provisions for a flare as outlined in the General Provisions (40 CFR 63, Subpart A)[2] (i.e., monitor for presence of a flame) was the only monitoring option considered. The monitoring options evaluated for a dedicated thermal combustion device for the CRUCR vents included specific organic HAP CEM, surrogate of organic HAP (THC/TOC) CEM, and continuous parametric monitoring. Due to the potentially acidic environment within the combustion unit (from the formation or prior existence of hydrogen chloride in the vent stream), the useful life of a CEM probe is uncertain and expected to be short. That is, both the organic HAP CEM and the THC/TOC CEM were considered unproven technologies for the CRUCR vent streams. Consequently, continuous parametric monitoring of temperature was selected as the only monitoring option for the CRUCR vent streams that are exhausted to a dedicated thermal combustion unit.

For the CRUCR coke burn vent, the primary HAP emitted from the depressurization/purge and the rejuvenation/final purge vent cycles are hydrogen chloride (HCl) and chlorine. Continuous HCl monitors are commercially available, but no refineries were identified that employed a continuous HCl monitor for the CRUCR coke burn vent. Continuous monitoring of the gas and liquid flow/recirculation rates were selected as indicators of proper control device operation.

7.3 MONITORING OPTIONS FOR THE SRU VENT

Carbonyl sulfide and carbon disulfide are the primary HAP emitted from the SRU vent. A CEM specific to just these two HAP is not commercially available at this time. However, CEMs for monitoring reduced sulfur compound emissions are commercially available and are in-use at several refineries for the SRU vent to show compliance with the petroleum refinery NSPS (40 CFR 60, Subpart J).[3] Although reduced sulfur compounds are a surrogate of the HAP emissions, it was considered a to be an excellent surrogate since reduced sulfur compounds consist only of the two specified sulfur HAP compounds plus hydrogen sulfide.

Only one parametric monitoring option was identified for SRU vents and that monitoring option is applicable only to SRU that employ an incinerator. temperature and excess oxygen were selected as the indicators of proper control device performance.

7.4 REFERENCES

1. Code of Federal Regulations. Title 40, Part 60, Subpart J. Standards of Performance for Petroleum Reifineries. U.S. Government Printing Office. Washington ,D.C. July 1, 1992.

2. Code of Federal Regulations. Title 40, Part 63, Subpart A. General Provisions. U.S. Government Printing Office. Washington ,D.C. July 1, 1992.

3. Reference 1.

8.0 COST OF CONTROLS FOR MODEL PLANTS

This chapter presents information on control costs for the various control equipment that may be included in the control option control requirements. Control costs for each control device for each model plant are reported in terms of total capital investment (TCI), annual operating costs (AOC), and total annualized costs (TAC) in late 1996 dollars. The basis for calculating these control costs are also described.

8.1 COSTS OF CONTROL DEVICES FOR CCUCR VENT

In this section, control costs are developed for selected control devices applicable for reducing HAP emissions from the CCUCR vent. The control devices selected for cost analysis for the CCUCR vent include: ESPs, venturi wet scrubbers, and CO boilers/incinerators. A correlation of the CCUCR flow rate versus CCU throughput was derived based on the available data to estimate model plant CCUCR vent flow rates.[1] The predicted model plant CCUCR flow rates are summarized in Table 8-1. The control device design and cost analyses were then performed based on these model CCUCR vent flow rates.

TABLE 8-1. MODEL PLANT CCUCR VENT FLOW RATES

No.	Size	CCU capacity (bbl/day)	Vent Flow Rate w/no CO Boiler Q(scfm)[1]	Vent Flow Rate w/CO Boiler Q(scfm)[1]
1	Small	8,300	15,000	20,000
2	Medium	25,000	55,000	70,000
3	Large	70,000	140,000	200,000

[1] Standard conditions at 60°F as defined in ICR.

8.1.1 Costs for ESPs

The costing procedures outlined in EPA's Control Cost Manual were used to develop costs for ESPs.[2] The ESP design parameters were based on the model plant vent flow rates and typical operating parameters as reported in responses to EPA's information collection requests (ICR) and industry supported surveys. The mean mass diameter was estimated to be 4 μm based on the assumption that cyclone separators (used to minimize catalyst loss from the CCUCR) will generally pass particles with diameters of 10 μm and less. It was assumed that the dust would not have severe back corona effects (i.e., a resistivity of less than 2×10^{11} ohm-cm was assumed). The design parameters used to develop costs for ESPs are summarized in Table 8-2.

TABLE 8-2. DESIGN VALUES FOR ESP

Parameter	Value
ESP Type	Plate & wire
Inlet PM (grains/cu.ft)	0.20
Design outlet PM (grains/cu.ft)	0.02
Required design efficiency (E)	0.90
Penetration (p = 1 - E)	0.10
Temperature (°K)	478
Resistivity (ohm-cm)	2.0E+09
Inlet mass mean diameter, MMD (μm)	4
Sneakage (Sn)	0.07
Rapping Re-entrainment (RR)	0.124
MMD for most penetrating size (μm)	2
MMD for rapping puff size (μm)	3
Design flow rate, Q (acfm)	Q(scfm)xT (°K)/289

Based on the ESP design parameters in Table 8-2, the projected specific collection area is 717 ft^2/kacfm. The total capital investment, annual operating costs and total annual costs for model plant ESPs are summarized in Table 8-3. Equations for estimating the control costs based on inlet flow rate and the design values summarized in Table 8-2 are also provided Table 8-3.

TABLE 8-3a. MODEL PLANT CCUCR ESP CONTROL COSTS[1] - TCI

No.	Size	CCU capacity (bbl/day)	TCI for CCU w/o CO Boiler ($1,000)	TCI for CCU w/CO Boiler ($1,000)
1	Small	8,300	1,500	1,800
2	Medium	25,000	3,200	3,900
3	Large	70,000	6,900	9,200
TCI ($1,000) = [0.0416 × Q(scfm)[2]] + 943				

TABLE 8-3b. MODEL PLANT CCUCR ESP CONTROL COSTS[1] - AOC

No.	Size	CCU capacity (bbl/day)	AOC for CCU w/o CO Boiler ($1,000)	AOC for CCU w/CO Boiler ($1,000)
1	Small	8,300	150	180
2	Medium	25,000	340	410
3	Large	70,000	740	1,000
AOC ($1,000) = [0.00468 × Q(scfm)[2]] + 85				

TABLE 8-3c. MODEL PLANT CCUCR ESP CONTROL COSTS[1] - TAC

No.	Size	CCU capacity (bbl/day)	TAC for CCU w/o CO Boiler ($1,000)	TAC for CCU w/CO Boiler ($1,000)
1	Small	8,300	300	350
2	Medium	25,000	640	780
3	Large	70,000	1,400	1,900
TAC ($1,000) = [0.0086 × Q(scfm)[2]] + 174				

[1] Costs rounded to 2 significant digits or nearest $100,000.

[2] Based on standard conditions at 60°F.

8.1.2 Cost for Venturi Wet Scrubbers

The costing procedures outlined in EPA's Handbook - Control Technologies for Hazardous Air Pollutants were used to develop costs for venturi scrubbers.[3] The venturi scrubber design parameters were based on the same model plant vent flow rates as used to estimate costs for ESPs. Again, the mean mass diameter was estimated to be 4 μm based on the assumption that cyclone separators (used to minimize catalyst loss from the CCUCR) will generally pass particles with diameters of 10 μm and less. The design parameters used to develop costs for venturi scrubbers are summarized in Table 8-4.

The total capital investment, annual operating costs and total annual costs for model plant venturi scrubbers are summarized in Table 8-5. Equations for estimating the control costs based on inlet flow rate and the design values summarized in Table 8-4 are also provided Table 8-5.

TABLE 8-4. DESIGN VALUES FOR VENTURI SCRUBBERS

Parameter	Value
Inlet PM (grains/cu.ft)	0.20
Design outlet PM (grains/cu.ft)	0.02
Required design efficiency (E)	0.90
Pressure drop at design efficiency, in H_20	10
Temperature (°F)	400
Moisture content (vol %)	5
Inlet mass mean diameter, MMD (μm)	4
Inlet mass mean diameter, MMD (μm)	4
Design flow rate, Q (acfm)	Q(scfm)×T (°R)/520

TABLE 8-5a. MODEL PLANT CCUCR VENTURI SCRUBBER CONTROL COSTS[1] - TCI

No.	Size	CCU capacity (bbl/day)	TCI for CCU w/o CO Boiler ($1,000)	TCI for CCU w/CO Boiler ($1,000)
1	Small	8,300	210	260
2	Medium	25,000	530	640
3	Large	70,000	1,100	1,400
TCI ($1,000) = exp[0.7229 × ln(Q(scfm)[2]) - 1.6086]				

TABLE 8-5b. MODEL PLANT CCUCR VENTURI SCRUBBER CONTROL COSTS[1] - AOC

No.	Size	CCU capacity (bbl/day)	AOC for CCU w/o CO Boiler ($1,000)	AOC for CCU w/CO Boiler ($1,000)
1	Small	8,300	300	370
2	Medium	25,000	880	1,100
3	Large	70,000	2,100	3,000
AOC ($1,000) = [0.0144 × Q(scfm)[2]] + 87				

TABLE 8-5c. MODEL PLANT CCUCR VENTURI SCRUBBER CONTROL COSTS[1] - TAC

No.	Size	CCU capacity (bbl/day)	TAC for CCU w/o CO Boiler ($1,000)	TAC for CCU w/CO Boiler ($1,000)
1	Small	8,300	330	410
2	Medium	25,000	960	1,200
3	Large	70,000	2,200	3,200
TAC ($1,000) = [0.0153 × Q(scfm)[2]] + 109				

[1] Costs rounded to 2 significant digits or nearest $100,000.

[2] Based on standard conditions at 60°F.

8.1.3 Costs for CO Boilers/Incineration

The control costs for incinerators were estimated using the costing procedures outlined in EPA's Control Cost Manual.[4] The incinerator design parameters were based on the model plant vent flow rates for CCU regenerators that do not have CO boilers. It was assumed that the CCUCR flue gas was at 1,200°F with 2 percent CO content (by volume). To minimize fuel requirements, the feed air to the incinerator is preheated by the incinerator exhaust (a 35 percent recuperative incinerator is more than sufficient); the total air requirements were determined from the system energy balance and a design outlet oxygen concentration of 2 percent (by volume). The total capital investment, annual operating costs and total annual costs for model plant incinerators for the CCUCR vent are summarized in Table 8-6.

Cost function equations were developed for model plant incinerators for the CCUCR vent based on linear regression analysis of the cost data summarized in Table 8-6 and exhaust gas flow rates (Q in scfm). The cost function equations for CCUCR incinerators follow.

$$\text{TCI } (\$1{,}000) = \exp\{0.36787 \times \ln(Q) + 2.5925\}$$

$$\text{AOC } (\$1{,}000) = 0.01041 \times Q + 59$$

$$\text{TAC } (\$1{,}000) = 0.01107 \times Q + 120$$

TABLE 8-6. MODEL PLANT CCUCR INCINERATOR CONTROL COSTS[1] - TCI, AOC AND TAC

No.	Size	CCU capacity (bbl/day)	TCI ($1,000)	AOC ($1,000)	TAC ($1,000)
1	Small	8,300	460	210	280
2	Medium	25,000	730	630	740
3	Large	70,000	1,100	1,500	1,700

[1] Costs rounded to 2 significant digits or nearest $100,000.

8.2 COSTS OF CONTROL DEVICES FOR CRUCR VENT

In this section, control costs are developed for selected control devices applicable for reducing HAP emissions from the CRUCR vent. The control devices selected for cost analysis for the CRUCR vent include wet scrubbers and caustic injection. [Currently assumed that all purge vents to flare or refinery fuel gas system are already in-place.] As the magnitude and duration of the CRUCR vent flows are dependent on the type of CRUCR (semi-regenerative, cyclic or continuous) as well as on the throughput of the CRU, nine model CRUCR vents were developed based on the type of CRUCR and CRU throughput ranges. The flow rates and durations of the model plant were selected based on an analysis of information in the EPA data base.[5] Table 8-7 summarizes the key parameters of the CRUCR model vents.

TABLE 8-7. MODEL PLANT CRUCR VENT FLOW RATES

No.	CRUCR Type	CRU Throughput Range (1,000 bpd)	Coke Burn Vent Flow Rate (scfm)[1]	Annual Coke Burn Vent Duration (hrs/yr)
1	Semi-Regen.	0 to <15	15,000	72
2	Semi-Regen.	15 to 30	20,000	90
3	Semi-Regen.	>30	30,000	120
4	Cyclic	0 to <15	600	2,400
5	Cyclic	15 to 30	800	3,000
6	Cyclic	>30	1,200	3,600
7	Continuous	0 to <15	150	8,640
8	Continuous	15 to 30	250	8,640
9	Continuous	>30	500	8,640

[1] Standard conditions at 60°F as defined in ICR.

The control device design and cost analyses were then performed based on these model CRUCR vent flow rates and durations. For the cyclic and continuous CRUCR, the control costs were developed using the control cost algorithms for packed-bed absorbers presented in EPA's Control Cost Manual.[6] For semi-regenerative units, control costs for a caustic spray chamber scrubber were derived using nearly the same control cost algorithms for packed-bed absorbers presented in EPA's Control Cost Manual, except no packing material was used in the spray chamber. The control cost factors developed for the model CRUCR units are presented in Table 8-8. These control cost factors were applied directly to a given CRUCR based on the CRU throughput. That is, no regression of the cost factors were performed to correlate CRUCR control costs with CRU throughput within a given CRU throughput range.

TABLE 8-8. MODEL PLANT CRUCR WET SCRUBBER/ABSORBER CONTROL COSTS[1] - TCI, AOC AND TAC

No.	Regen. Type	CRU capacity (1000 bpd)	TCI ($1,000)	AOC ($1,000)	TAC ($1,000)
1	Semi	<15	38	6	11
2	Semi	15 to 30	47	9	16
3	Semi	>30	64	16	25
4	Cyclic	<15	45	13	20
5	Cyclic	15 to 30	54	16	24
6	Cyclic	>30	68	20	30
7	Cont.	<15	21	41	44
8	Cont.	15 to 30	27	41	45
9	Cont.	>30	41	42	48

[1] Costs rounded to 2 significant digits or nearest $1,000.

8.3 COSTS OF CONTROL DEVICES FOR SULFUR PLANT VENT

This section presents the control costs for incinerators used to reduce HAP emissions from the SRU vent. A correlation of the SRU tail gas flow rate versus sulfur production rate was derived based on the data available in the EPA database. The EPA database was also used to characterize the SRU tail gas.[7] The predicted model plant SRU flow rates are summarized in Table 8-9. All model SRU units (that require an incinerator) are assumed to have tail gas with the following properties:

Temperature = 275°F
Reduced Sulfur Compound Concentration = 4,000 ppmv
Oxygen Concentration = 0 ppmv.

TABLE 8-9. MODEL PLANT SRU VENT FLOW RATES

No.	Size	Sulfur Production Rate (long tons/day)	Vent Flow Rate Q(scfm)[1]	Operating Hours (hrs/yr)
1	Small	30	1,950	8,640
2	Medium	120	7,800	8,640
3	Large	480	31,200	8,640

[1] Standard conditions at 60°F as defined in ICR.

The control costs for SRU incinerators were estimated using the costing procedures outlined in EPA's Control Cost Manual.[8] The incinerator design parameters were based on the model plant vent flow rates for SRUs. To minimize fuel requirements, both the combustion air and the SRU tail gas are preheated by the incinerator exhaust; a recuperative incinerator with 70 percent energy recovery was employed. The total air requirements were determined from the system energy balance and a design outlet oxygen concentration of 2 percent (by volume). The total capital investment, annual operating costs and total annual costs for model plant incinerators for the SRU vent are summarized in Table 8-10.

TABLE 8-10. MODEL PLANT SRU INCINERATOR CONTROL COSTS[1] - TCI, AOC AND TAC

No.	Size	Sulfur Prod.Rate (long tpd)	TCI ($1,000)	AOC ($1,000)	TAC ($1,000)
1	Small	30	360	110	160
2	Medium	120	530	260	340
3	Large	480	810	870	980

[1] Costs rounded to 2 significant digits or nearest $100,000.

Cost function equations were developed for model plant incinerators for the CCUCR vent based on linear regression analysis of the cost data summarized in Table 8-6 and exhaust gas flow rates (Q in scfm). The cost function equations for SRU incinerators follow.

$$\text{TCI } (\$1{,}000) = \exp\{0.29295\times \ln(Q)+3.6625\}$$
$$\text{AOC } (\$1{,}000) = 0.02605\times Q + 57$$
$$\text{TAC } (\$1{,}000) = 0.02811\times Q + 109$$

8.4 COSTS OF MONITORING, REPORTING, AND RECORDKEEPING

This section presents the costs associated with control device monitoring, reporting and recordkeeping for each of the different types of control devices / refinery vent combinations. First costs and initial annual costs for continuous emission monitors (CEMs) are given in Table 8-11 for each type of subject unit and for alternative means of compliance. CEMs for the units may measure offgas characteristics (constituent concentration or temperature) or equipment operating parameters (voltage, current, pressure drop, or flow rates). Although purchase costs of monitors may vary from a few hundred dollars to many thousands of dollars, depending on the parameter being monitored, the major cost of a CEM system lies in time and materials costs for planning, installing, maintaining, certifying, and recertifying the system for its lifetime. The costs in Table 1 include these items. In particular, relative accuracy test audits required for extractive sampling contribute significantly to annual costs. All costing was done using EPA's EMTIC program, with costs escalated to late 1996.[9]

Elements of the EMTIC program for first costs include: planning, selection of equipment, support facilities, purchase of the CEM, installation and checking, performance test, and preparation of a QA/QC plan. Elements for the first year's annual cost include: operation and maintenance, relative accuracy test audit and supplemental audit (for extractive gas CEMs), quarterly cylinder gas audits (for calibration), record keeping and reporting, and annual review and update. Where process monitoring instruments such as temperature, pressure, voltage, and current instruments are used, they are assumed to be part of the control system and have their purchase costs allocated to the process rather than to the CEM system. However, associated record keeping and reporting, annual review and update, and some operation and maintenance costs are assigned to CEM system costs.

The costs in Table 1 have large error bands, but should be useful for comparing gas CEMs vs parameter monitoring. While monitor costs are generally supplied by EMTIC or a vendor quote, the multimetals CEM cost is an estimate.

Table 8-11. First cost and initial annual cost for continuous emission monitors on CCUs, CRUs, and SRUs

Unit	Pollutant	Monitored parameter	First cost, $	Initial annual cost, $
CCU	Organic HAP	CO	97,100	63,400
		Temperature	18,900	19,500
		HAP/TOC	91,300	63,900
	Particulate matter	ESP: volts/amps	32,000	20,300
		WS: DP, liq. and gas flow rates	37,300	20,400
		Opacity	41,200	18,400
	Metallic HAP	Mulitmetals (by CEM)	132,700	66,600
		Opacity	41,200	18,400
CRU	HCl	HCl (by CEM)	104,000	65,000
		HCl (by M26A)	Not applicable	13,800
	Organic Hap from flare	per general provisions	0	0
	Organic Hap from incinerator	Temperature	18,900	19,500
SRU	COS/CS_2 from incinerator	Total reduced sulfur	117,600	65,900
		Temperature	18,900	19,500

CCU	Catalytic cracking unit
CEM	continuous emission monitor
CRU	Catalyst regeneration unit
DP	Differential pressure
ESP	Electrostatic precipitator
M26A	EPA test method 26A for HCl
SRU	Sulfur recovery unit
HAP	Hazardous air pollutant
TOC	Total organic carbon
WS	Wet scrubber

8.5 REFERENCES

1. U.S. Environmental Protection Agency. Refinery process vent data base...

2. U.S. Environmental Protection Agency. OAQPS Control Cost Manual. Publication No. EPA/450/3-90-006. Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 1990.

3. U.S. Environmental Protection Agency. Handbook - Control Technologies for Hazardous Air Pollutants. Publication No. EPA/625/6-91/014. Office of Research and Development, Washington, DC. June 1991. pp. 4-80 through 4-90.

4. Reference 2.

5. Reference 1.

6. Reference 2.

7. Reference 1.

8. U.S. Environmental Protection Agency...

APPENDIX A

KEY DATES IN DEVELOPMENT OF BID

TABLE A-1. KEY DATES IN THE DEVELOPMENT OF THE BID

Date	Event
July 16, 1992	The EPA published initial list of hazardous air pollutant (HAP) emission source categories (57 FR 31576)
August 16-17, 1995	EPA conducted information gathering site visits to three petroleum refineries in Pennsylvania and New Jersey
August 18, 1995	The EPA published National Emission Standards for Hazardous Air Pollutants (NESHAP: Petroleum Refineries; Final Rule (60 FR 43244). This rule, termed Petroleum Refinery MACT I, deferred setting NESHAP for three vents: catalyst regeneration vents on catalytic cracking units (CCU) and catalytic reforming units (CRU) and vents from sulfur recovery units (SRU).
August 31, 1995 and September 1, 1995	EPA conducted information gathering site visits to two petroleum refineries in Louisiana.
December 1, 1995	EPA held kick-off Presumptive MACT meeting with regulatory agency representatives.
December 7, 1995	EPA held kick-off Presumptive MACT meeting with representatives of industrial stakeholders.
June 24, 1996	EPA met with representatives of emission control device manufacturers.
February 28, 1997	EPA finalized the Preliminary Presumptive MACT for Petroleum Refinery Process Vents: FCC Units, Reformers, and Sulfur Plants.

TABLE A-1. KEY DATES (Continued)

Date	Event
July 29, 1997	EPA held meeting with small business petroleum refineries to communicate EPA's policies regarding Small Business Regulatory Enforcement Fairness Act (SBREFA).
September 12, 1997	EPA conducted an information gathering site visit to a small business petroleum refinery in Indiana.
September 15, 1997 through September 17, 1997	EPA conducted information gathering site visits to four small petroleum refineries in Wyoming and Utah that have non-conventional units (non-fluid CCU and non-Claus SRU).

APPENDIX B. HAP EMISSIONS DATA

This appendix contains the HAP emissions data used to develop estimates of emissions in Chapter 5 for model plants and for all units nationwide. The data for catalytic cracking and catalytic reforming given in Tables B-1 and B-2 were provided in a database from API and included the results of their survey of the industry.[1] The data for sulfur recovery units in Table B-3 were from responses to section 114 questionnaires compiled by the EPA.[2] These data are also summarized in the document developed for the presumptive MACT process.[3]

REFERENCES

1. Letter from David Hansell, EER, to Robert Lucas, U.S.EPA, transmitting the Detailed API CCU and CRU Data Base; 2nd Draft. January 23, 1997

2. U.S Environmental Protection Agency. Responses to Information Collection Request for Petroleum Refineries. Office of Air Quality Planning and Standards, Research Triangle Park, NC. 1992.

3. U.S Environmental Protection Agency. Presumptive MACT for Petroleum Refinery Process Vents: FCC Units, Reformers, and Sulfur Recovery Plants. Appendix B-Summary of Emissions Data. Office of Air Quality Planning and Standards, Research Triangle Park, NC. 1997.

TABLE B-1. EMISSIONS DATA FOR CCU REGENERATION (abbreviations are explained at the end of the table)

Combustion type	Hydro treat	APC System	Sample location	Substance	Data source	Factor (lb/mm bbl)
NA	NA	COB	COB Outlet	1,3-Butadiene	114	7.00e-04
NA	NA	COB	COB Outlet	1,3-Butadiene	114	9.00e-04
Complete	Yes	C\COB\ESP	ESP Outlet	1,3-Butadiene	Test	4.82e-02
NA	NA	ESP	ESP Outlet	Acetaldehyde	ICR	2.99e+00
NA	NA	ESP	ESP Outlet	Acetaldehyde	Test	3.00e+00
Partial	NA	C\COB\ESP	ESP Outlet	Acetaldehyde	Test	1.34e+01
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Acetaldehyde	Test	1.35e+01
Complete	Yes	C\COB\ESP	ESP Outlet	Acetaldehyde	Test	2.07e+01
NA	NA	COB\ESP	NA	Acetaldehyde	Test	2.47e+01
NA	NA	COB\ESP	ESP Outlet	Acetaldehyde	114	3.02e+01
Partial	NA	C\COB\ESP	ESP Outlet	Acetaldehyde	Test	3.41e+01
Partial	Yes	C\COB\ESP	ESP Outlet	Benzene	Test	7.25e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Benzene	Test	1.98e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Benzene	Test	2.79e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Benzene	Test	1.06e+01
Partial	Yes	C\COB\ESP	ESP Outlet	Benzene	Test	1.17e+01
NA	NA	ESP	ESP Outlet	Benzene	Test	3.97e+01
NA	NA	ESP	ESP Outlet	Benzene	ICR	4.30e+01
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Cyanide	ICR	2.83e+01
Complete	Yes	WHB\ESP\COB	COB Outlet	Cyanide	Test	3.55e+01
NA	NA	ESP	ESP Outlet	Formaldehyde	ICR	1.03e+01
NA	NA	ESP	ESP Outlet	Formaldehyde	Test	1.04e+01
Partial	NA	C\COB\ESP	ESP Outlet	Formaldehyde	Test	1.31e+01
Complete	Yes	C\COB\ESP	ESP Outlet	Formaldehyde	Test	1.63e+01
Partial	NA	C\COB\ESP	ESP Outlet	Formaldehyde	ICR	1.92e+01
NA	NA	COB\ESP	NA	Formaldehyde	Test	2.66e+01
Partial	NA	C\COB\ESP	ESP Outlet	Formaldehyde	Test	2.83e+01
NA	NA	COB\ESP	ESP Outlet	Formaldehyde	114	3.15e+01
Complete	Yes	NA	NA	Formaldehyde	SV	7.89e+01
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Formaldehyde	ICR	9.29e+02
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Formaldehyde	Test	9.56e+02
Partial	NA	C\COB\ESP	ESP Outlet	Formaldehyde	Test	6.18e+04
Partial	NA	C\COB\ESP	ESP Outlet	Formaldehyde	Test	1.40e+05
NA	NA	C\ESP	ESP Outlet	Hydrogen Cyanide	Test	7.84e-01
NA	NA	COB\ESP	NA	Hydrogen Cyanide	Test	1.40e+01
Complete	Yes	C\COB\ESP	ESP Outlet	Hydrogen Cyanide	Test	2.46e+01
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Hydrogen Cyanide	Test	2.90e+01
Partial	Yes	C\COB\ESP	NA	Hydrogen Cyanide	114	1.94e+02
NA	NA	ESP	ESP Outlet	Hydrogen Cyanide	Test	2.58e+03
Complete	Yes	WHB\VS	VS Outlet	n-Hexane	114	5.41e+01
Partial	Yes	C\COB\ESP	ESP Outlet	Toluene	Test	8.05e-02
Partial	Yes	C\COB\ESP	ESP Outlet	Toluene	Test	9.01e-02
Partial	Yes	C\COB\ESP	ESP Outlet	Toluene	Test	1.27e-01

TABLE B-1. EMISSIONS DATA FOR CCU REGENERATION (continued)

Combustion type	Hydro treat	APC System	Sample location	Substance	Data source	Factor (lb/mm bbl)
Partial	Yes	C\COB\ESP	ESP Outlet	Toluene	Test	3.74e+00
NA	NA	COB\ESP	ESP Outlet	Toluene	ICR	1.38e+03
NA	NA	COB\ESP	ESP Outlet	Total Xylene	ICR	9.00e+01
Partial	Yes	C\COB\ESP	ESP Outlet	2-Methylnaphthalene	Test	2.61e-02
Complete	Yes	WHB\ESP\COB	COB Outlet	Phenol	Test	2.27e-04
Complete	Yes	C\COB\ESP	ESP Outlet	Phenol	Test	8.41e-01
NA	NA	ESP	ESP Outlet	Phenol	ICR	1.11e+00
NA	NA	ESP	ESP Outlet	Phenol	Test	1.15e+00
NA	NA	COB\ESP	ESP Outlet	Phenol	114	2.15e+01
NA	NA	C\ESP	ESP Outlet	Phenol	Test	4.09e+01
Complete	Yes	WHB\ESP\COB	COB Outlet	Acenaphthene	Test	4.90e-04
Partial	Yes	C\COB\ESP	ESP Outlet	Acenaphthene	Test	6.08e-03
Complete	Yes	WHB\ESP\COB	COB Outlet	Acenaphthylene	Test	3.54e-04
Complete	Yes	C\COB\ESP	ESP Outlet	Acenaphthylene	Test	2.57e-01
Complete	Yes	WHB\ESP\COB	COB Outlet	Anthracene	Test	1.13e-03
NA	NA	C\ESP	ESP Outlet	Anthracene	Test	2.03e-01
Complete	Yes	WHB\ESP\COB	COB Outlet	Benzo(a)anthracene	Test	5.24e-04
Partial	Yes	C\COB\ESP	ESP Outlet	Benzo(a)pyrene	Test	1.06e-02
Complete	Yes	WHB\ESP\COB	COB Outlet	Benzo(b)fluoranthene	Test	1.06e-03
Partial	Yes	C\COB\ESP	ESP Outlet	Benzo(b)fluoranthene	Test	5.94e-03
Complete	Yes	WHB\ESP\COB	COB Outlet	Benzo(e)pyrene	Test	4.54e-04
Partial	Yes	C\COB\ESP	ESP Outlet	Benzo(g,h,i)perylene	Test	4.60e-03
Complete	Yes	WHB\ESP\COB	COB Outlet	Benzo(k)fluoranthene	Test	3.66e-04
Partial	Yes	C\COB\ESP	ESP Outlet	Benzo(k)fluoranthene	Test	4.86e-03
Complete	Yes	WHB\ESP\COB	COB Outlet	Chrysene	Test	2.56e-03
Partial	Yes	C\COB\ESP	ESP Outlet	Chrysene	Test	3.98e-03
Partial	Yes	C\COB\ESP	ESP Outlet	dibenz(a,h)anthracene	Test	4.58e-03
Partial	Yes	C\COB\ESP	ESP Outlet	Fluoranthene	Test	4.92e-03
NA	NA	C\ESP	ESP Outlet	Fluoranthene	Test	2.71e-01
Complete	Yes	WHB\ESP\COB	COB Outlet	Fluorene	Test	1.92e-03
Partial	Yes	C\COB\ESP	ESP Outlet	Fluorene	Test	6.52e-03
NA	NA	C\ESP	ESP Outlet	Fluorene	Test	1.01e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Indeno(1,2,3-cd)pyrene	Test	4.38e-03
Complete	Yes	WHB\ESP\COB	COB Outlet	Naphthalene	Test	1.02e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Naphthalene	Test	8.64e-01
NA	NA	ESP	ESP Outlet	Naphthalene	ICR	1.52e+00
NA	NA	ESP	ESP Outlet	Naphthalene	Test	1.55e+00
NA	NA	C\ESP	ESP Outlet	Naphthalene	Test	1.68e+00

TABLE B-1. EMISSIONS DATA FOR CCU REGENERATION (continued)

Combustion type	Hydro treat	APC System	Sample location	Substance	Data source	Factor (lb/mm bbl)
NA	NA	COB\ESP	NA	PAH (Total)	Test	8.05e+00
Partial	Yes	C\COB\ESP	COB Outlet	PAH (Total)	114	1.94e+02
Complete	Yes	WHB\ESP\COB	COB Outlet	Phenanthrene	Test	1.15e-02
Partial	Yes	C\COB\ESP	ESP Outlet	Phenanthrene	Test	2.40e-02
NA	NA	ESP	ESP Outlet	Phenanthrene	Test	1.48e-01
NA	NA	C\ESP	ESP Outlet	Phenanthrene	Test	7.94e-01
NA	NA	COB\ESP	NA	Phenolics (Total)	Test	2.02e+01
Complete	Yes	WHB\ESP\COB	COB Outlet	Pyrene	Test	2.49e-03
Partial	Yes	C\COB\ESP	ESP Outlet	Pyrene	Test	4.42e-03
NA	NA	COB	COB Outlet	Antimony	114	3.20e-02
Partial	Yes	C\COB\ESP	ESP Outlet	Antimony	Test	4.36e-02
NA	NA	COB	COB Outlet	Antimony	114	4.40e-02
Complete	Yes	ESP	ESP Outlet	Antimony	114	5.00e-02
Complete	Yes	ESP	ESP Outlet	Antimony	114	1.00e-01
Partial	No	I	Regen Outlet	Antimony	Test	2.33e+00
Complete	Yes	ESP	ESP Outlet	Antimony	114	5.53e+00
Partial	No	C\ESP\COB	COB Outlet	Antimony	ICR	9.95e+00
NA	NA	COB	COB Outlet	Arsenic	114	1.00e-03
NA	NA	COB	COB Outlet	Arsenic	114	1.00e-03
Partial	Yes	C\COB\ESP	ESP Outlet	Arsenic	Test	6.87e-02
Partial	Yes	C\COB\ESP	ESP Outlet	Arsenic	Test	7.40e-02
Complete	Yes	C\COB\ESP	ESP Outlet	Arsenic	Test	1.21e-01
Partial	NA	C\COB\ESP	ESP Outlet	Arsenic	Test	1.67e-01
NA	NA	C\ESP	ESP Outlet	Arsenic	Test	2.29e-01
Partial	NA	C\COB\ESP	ESP Outlet	Arsenic	Test	2.89e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Arsenic	Test	3.97e-01
Partial	NA	C\COB\ESP	ESP Outlet	Arsenic	ICR	4.70e-01
Partial	NA	C\COB\ESP	ESP Outlet	Arsenic	Test	1.12e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Arsenic	Test	1.43e+00
Partial	No	I	Regen Outlet	Arsenic	Test	1.70e+00
NA	NA	COB	COB Outlet	Beryllium	114	2.00e-03
NA	NA	COB	COB Outlet	Beryllium	114	3.00e-03
Partial	No	I	Regen Outlet	Beryllium	Test	5.36e-02
Partial	Yes	C\COB\ESP	ESP Outlet	Beryllium	Test	6.58e-02
NA	NA	COB	COB Outlet	Cadmium	114	4.00e-03
NA	NA	COB	COB Outlet	Cadmium	114	5.00e-03
Partial	NA	C\COB\ESP	ESP Outlet	Cadmium	ICR	2.00e-02
Partial	NA	C\COB\ESP	ESP Outlet	Cadmium	Test	2.06e-02
Partial	Yes	C\COB\ESP	ESP Outlet	Cadmium	Test	4.49e-02
Partial	NA	C\COB\ESP	ESP Outlet	Cadmium	Test	9.24e-02
NA	NA	ESP	ESP Outlet	Cadmium	ICR	2.80e-01
NA	NA	ESP	ESP Outlet	Cadmium	Test	2.96e-01
Partial	No	I	Regen Outlet	Cadmium	Test	3.41e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Cadmium	Test	8.70e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Cadmium	Test	1.65e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Cadmium	Test	2.82e+00
NA	NA	COB	COB Outlet	Chromium	114	4.30e-02

TABLE B-1. EMISSIONS DATA FOR CCU REGENERATION (continued)

Combustion type	Hydro treat	APC System	Sample location	Substance	Data source	Factor (lb/mm bbl)
NA	NA	COB	COB Outlet	Chromium	114	5.90e-02
Partial	NA	C\COB\ESP	ESP Outlet	Chromium	Test	1.26e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Chromium	Test	2.43e-01
Partial	NA	C\COB\ESP	ESP Outlet	Chromium	ICR	2.90e-01
Complete	Yes	WHB\ESP\COB	COB Outlet	Chromium	Test	4.99e-01
Partial	NA	C\COB\ESP	ESP Outlet	Chromium	Test	5.01e-01
NA	NA	C\ESP	ESP Outlet	Chromium	Test	5.66e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Chromium	Test	8.30e-01
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Chromium	ICR	9.00e-01
Complete	Yes	C\COB\ESP	ESP Outlet	Chromium	Test	9.47e-01
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Chromium	Test	9.79e-01
Partial	No	I	Regen Outlet	Chromium	Test	1.11e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Chromium	Test	1.16e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Chromium	Test	2.10e+00
NA	NA	ESP	ESP Outlet	Chromium	ICR	2.59e+00
NA	NA	ESP	ESP Outlet	Chromium	Test	2.93e+00
Partial	NA	C\COB\ESP	ESP Outlet	Chromium	Test	7.58e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Chromium	Test	1.18e+01
Partial	NA	C\COB\ESP	ESP Outlet	Chromium	Test	2.71e+01
NA	NA	COB	COB Outlet	Cobalt	114	6.00e-03
NA	NA	COB	COB Outlet	Cobalt	114	9.00e-03
Complete	Yes	ESP	ESP Outlet	Cobalt	114	2.10e-01
Complete	Yes	ESP	ESP Outlet	Cobalt	114	4.10e-01
Partial	No	I	Regen Outlet	Cobalt	Test	1.13e+00
Complete	Yes	ESP	ESP Outlet	Cobalt	114	1.49e+00
NA	NA	COB	COB Outlet	Lead	114	1.05e-01
NA	NA	COB	COB Outlet	Lead	114	1.45e-01
Complete	Yes	WHB\VS	VS Outlet	Lead	114	1.80e-01
Partial	NA	C\COB\ESP	ESP Outlet	Lead	ICR	2.70e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Lead	Test	2.81e-01
Complete	Yes	WHB\ESP\COB	COB Outlet	Lead	Test	2.82e-01
Partial	NA	C\COB\ESP	ESP Outlet	Lead	Test	4.54e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Lead	Test	6.06e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Lead	Test	1.53e+00
Complete	Yes	C\COB\ESP	ESP Outlet	Lead	Test	1.65e+00
Partial	NA	C\COB\ESP	ESP Outlet	Lead	Test	2.84e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Lead	Test	3.50e+00
NA	NA	C\ESP	ESP Outlet	Lead	Test	4.52e+00
Partial	NA	C\COB\ESP	ESP Outlet	Lead	Test	5.45e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Lead	Test	6.20e+00
Partial	No	I	Regen Outlet	Lead	Test	6.29e+00
NA	NA	I\ESP	NA	Lead	114	6.72e+00
Partial	NA	C\COB\ESP	ESP Outlet	Lead	Test	9.17e+00
Partial	NA	C\COB\ESP	ESP Outlet	Manganese	Test	3.69e-01

TABLE B-1. EMISSIONS DATA FOR CCU REGENERATION (continued)

Combustion type	Hydro treat	APC System	Sample location	Substance	Data source	Factor (lb/mm bbl)
Complete	Yes	WHB\ESP\COB	COB Outlet	Manganese	Test	3.71e-01
NA	NA	C\ESP	ESP Outlet	Manganese	Test	6.26e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Manganese	Test	1.05e+00
Partial	NA	C\COB\ESP	ESP Outlet	Manganese	Test	1.78e+00
Complete	Yes	C\COB\ESP	ESP Outlet	Manganese	Test	2.09e+00
NA	NA	ESP	ESP Outlet	Manganese	ICR	2.32e+00
NA	NA	ESP	ESP Outlet	Manganese	Test	2.45e+00
Partial	No	I	Regen Outlet	Manganese	Test	6.69e+00
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Manganese	ICR	1.08e+01
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Manganese	Test	1.10e+01
Partial	NA	C\COB\ESP	ESP Outlet	Manganese	Test	1.42e+01
Partial	NA	C\COB\ESP	ESP Outlet	Manganese	Test	2.30e+01
NA	NA	COB	COB Outlet	Mercury	114	1.00e-03
NA	NA	COB	COB Outlet	Mercury	114	1.00e-03
Partial	NA	C\COB\ESP	ESP Outlet	Mercury	Test	3.07e-02
Partial	NA	C\COB\ESP	ESP Outlet	Mercury	Test	3.49e-02
Complete	Yes	C\COB\ESP	ESP Outlet	Mercury	Test	6.98e-02
NA	NA	C\ESP	ESP Outlet	Mercury	Test	7.04e-02
Partial	Yes	C\COB\ESP	ESP Outlet	Mercury	Test	1.48e-01
Partial	NA	C\COB\ESP	ESP Outlet	Mercury	Test	1.62e-01
NA	NA	ESP	ESP Outlet	Mercury	ICR	3.00e-01
NA	NA	ESP	ESP Outlet	Mercury	Test	3.19e-01
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Mercury	Test	4.58e-01
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Mercury	ICR	6.00e-01
Partial	No	I	Regen Outlet	Mercury	Test	2.88e+00
Complete	No	WHB\ESP	ESP Outlet	Nickel	ICR	2.20e-03
Partial	NA	C\COB\ESP	ESP Outlet	Nickel	ICR	2.00e-02
Partial	NA	C\COB\ESP	ESP Outlet	Nickel	Test	4.31e-01
Partial	No	COB	Regen Outlet	Nickel	114	5.50e-01
NA	NA	C\ESP	ESP Outlet	Nickel	Test	5.53e-01
Partial	NA	C\COB\ESP	ESP Outlet	Nickel	Test	8.62e-01
Complete	Yes	C\COB\ESP	ESP Outlet	Nickel	Test	1.39e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Nickel	Test	1.39e+00
Complete	Yes	ESP	ESP Outlet	Nickel	114	1.48e+00
Complete	Yes	WHB\ESP	ESP Outlet	Nickel	ICR	1.49e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Nickel	Test	2.39e+00
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Nickel	ICR	3.20e+00
Complete	Yes	WHB\VS	VS Outlet	Nickel	114	3.23e+00
Complete	Yes	ESP	ESP Outlet	Nickel	114	3.55e+00
Complete	Yes	C\WHB\ESP\COB	ESP Outlet	Nickel	Test	3.74e+00
Complete	Yes	WHB\ESP\COB	COB Outlet	Nickel	Test	5.21e+00
NA	NA	ESP	ESP Outlet	Nickel	ICR	5.47e+00

TABLE B-1. EMISSIONS DATA FOR CCU REGENERATION (continued)

Combustion type	Hydro treat	APC System	Sample location	Substance	Data source	Factor (lb/mm bbl)
Partial	Yes	C\COB\ESP	ESP Outlet	Nickel	Test	6.40e+00
Partial	NA	C\COB\ESP	ESP Outlet	Nickel	Test	6.54e+00
NA	NA	C	Cyclone Outlet	Nickel	ICR	7.19e+00
NA	NA	ESP	ESP Outlet	Nickel	ICR	8.03e+00
Complete	Yes	WHB\C\ESP	ESP Outlet	Nickel	ICR	1.05e+01
Partial	No	COB	COB Outlet	Nickel	114	1.34e+01
Complete	Yes	ESP	ESP Outlet	Nickel	114	1.35e+01
Partial	Yes	C\COB\ESP	ESP Outlet	Nickel	Test	1.41e+01
NA	NA	ESP	ESP Outlet	Nickel	Test	2.21e+01
Complete	Yes	NA	NA	Nickel	SV	2.79e+01
Partial	No	C\ESP\COB	COB Outlet	Nickel	ICR	4.31e+01
Partial	NA	C\COB\ESP	ESP Outlet	Nickel	Test	4.53e+01
Partial	No	I	Regen Outlet	Nickel	Test	3.36e+02
Partial	NA	C\COB\ESP	ESP Outlet	Selenium	ICR	2.00e-02
Complete	Yes	C\COB\ESP	ESP Outlet	Selenium	Test	3.23e-02
Partial	NA	C\COB\ESP	ESP Outlet	Selenium	Test	3.38e-02
Partial	NA	C\COB\ESP	ESP Outlet	Selenium	Test	2.54e-01
Partial	NA	C\COB\ESP	ESP Outlet	Selenium	Test	4.23e-01
NA	NA	C\ESP	ESP Outlet	Selenium	Test	9.34e-01
Complete	Yes	WHB\ESP\COB	COB Outlet	Selenium	Test	9.44e-01
Partial	Yes	C\COB\ESP	ESP Outlet	Selenium	Test	2.02e+00
Partial	No	I	Regen Outlet	Selenium	Test	3.34e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Selenium	Test	4.96e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Selenium	Test	7.61e+00
Partial	Yes	C\COB\ESP	ESP Outlet	Selenium	Test	1.40e+01
Partial	Yes	C\COB\ESP	ESP Outlet	Chlorine	Test	5.04e+00
Complete	Yes	WHB\ESP\COB	COB Outlet	HCl	Test	5.28e+02
Partial	Yes	C\COB\ESP	ESP Outlet	HCl	Test	6.67e+02
Partial	Yes	C\COB\ESP	ESP Outlet	HCl	Test	8.40e+02
Partial	Yes	C\COB\ESP	ESP Outlet	5F Total	Test	5.51e-07
Partial	Yes	C\COB\ESP	ESP Outlet	6F 123478	Test	6.24e-07
Partial	Yes	C\COB\ESP	ESP Outlet	6F 123678	Test	3.75e-07
Partial	Yes	C\COB\ESP	ESP Outlet	6F 234678	Test	6.51e-07
Partial	Yes	C\COB\ESP	ESP Outlet	6F Total	Test	1.07e-06
Partial	Yes	C\COB\ESP	ESP Outlet	7D 1234678	Test	9.45e-07
Partial	Yes	C\COB\ESP	ESP Outlet	7D Total	Test	9.45e-07

APC = air pollution control
C = cyclone
COB = carbon monoxide boiler
ESP = electrostatic precipitator
I = incinerator
ICR = information collection request
lb/mm bbl = pounds per million barrels
NA = not available
VS = venturi scrubber
WHB = waste heat boiler
5F = pentachlorodibenzofuran
6F = hexachlorodibenzofuran
7D = heptachlorodibenzo-p-dioxin

TABLE B-1. EMISSIONS DATA FOR CCU REGENERATION (continued)

114 = section 114 request

TABLE B-2. EMISSIONS DATA FOR CRU REGENERATION (abbreviations given at end of table)

Design	APC System	Sample location	Type	Substance	Data Source	Factor (lb/mm bbl)
Continuous	PC	Regen Outlet	Uncontrolled	1,2-Dichloroethane	114	
Cyclic	SCS/Flare	Regen Outlet	Uncontrolled	Benzene	114	5.00e-03
Continuous	PH	Heater Outlet	Controlled	Benzene	ICR	1.00e-01
Cyclic	SCS	SCS Outlet	Controlled	Benzene	114	2.14e-01
Cyclic	SCS/Flare	Regen Outlet	Uncontrolled	Benzene	114	4.27e+00
Cyclic	PS	Regen Outlet	Uncontrolled	Benzene	114	6.54e+00
Continuous	PH	Heater Outlet	Controlled	Benzene	ICR	7.09e+00
Cyclic	SCS/Flare	Flare Outlet	Controlled	Hydrogen Sulfide	114	7.10e-05
Cyclic	None	Regen Outlet	Uncontrolled	n-Hexane	114	8.56e+02
Continuous	PH	Heater Outlet	Controlled	Toluene	ICR	2.70e-01
Continuous	PH	Heater Outlet	Controlled	Toluene	ICR	1.89e+01
Continuous	PH	Heater Outlet	Controlled	Total Xylene	ICR	1.90e-01
Continuous	PH	Heater Outlet	Controlled	Total Xylene	ICR	1.37e+01
Continuous	None	Regen Outlet	Uncontrolled	VOC (Total)	114	5.85e+00
Cyclic	SCS	SCS Outlet	Controlled	VOC (Total)	114	1.71e+01
Cyclic	SCS/Flare	Flare Outlet	Controlled	VOC (Total)	114	7.96e+01
Cyclic	PS	Regen Outlet	Uncontrolled	VOC (Total)	114	1.99e+02
Cyclic	PS	Regen Outlet	Uncontrolled	VOC (Total)	114	6.42e+02
Semi-Regenerative	S	S Outlet	Controlled	VOC (Total)	114	7.41e+02
Cyclic	None	Regen Outlet	Uncontrolled	VOC (Total)	114	1.74e+03
Semi-Regenerative	CI\C	Cyclone Outlet	Controlled	VOC (Total)	114	7.99e+03
Semi-Regenerative	CS	CS Outlet	Controlled	Particulate	Test	5.79e-04
Cyclic	SCS/Flare	Regen Outlet	Uncontrolled	Particulate	114	5.94e-03
Cyclic	SCS/Flare	Regen Outlet	Uncontrolled	Particulate	114	3.49e+00
Continuous	None	Regen Outlet	Uncontrolled	Particulate	114	5.85e+00
Continuous	PC	Regen Outlet	Uncontrolled	Particulate	114	2.70e+01
Continuous	na	Heater Outlet	Controlled	Particulate	Test	1.78e+03
Semi-Regenerative	S	S Outlet	Controlled	Particulate	114	2.59e+03
Semi-Regenerative	CI\C	Cyclone Outlet	Controlled	Particulate	114	2.48e+04
Continuous	PH	Heater Outlet	Controlled	Naphthalene	ICR	1.00e-02
Continuous	PH	Heater Outlet	Controlled	Naphthalene	ICR	9.50e-01
Cyclic	SCS	SCS Outlet	Controlled	PAH (Total)	114	4.47e+00
Continuous	PC	Regen Outlet	Uncontrolled	PAH (Total)	114	4.35e+02
Continuous	None	Regen Outlet	Uncontrolled	PAH (Total)	114	9.57e+02
Continuous	None	Regen Outlet	Uncontrolled	PAH (Total)	114	3.79e+03
Semi-Regenerative	CS	CS Outlet	Controlled	Cadmium	Test	9.73e-08
Semi-Regenerative	CS	CS Outlet	Controlled	Chromium	Test	6.55e-07
Semi-Regenerative	VSA	VSA Outlet	Controlled	Chromium	ICR	1.50e-02
Semi-Regenerative	VSA	VSA Outlet	Controlled	Chromium	ICR	1.50e-02
Semi-Regenerative	VSA	VSA Outlet	Controlled	Chromium	ICR	2.10e-02

TABLE B-2. EMISSIONS DATA FOR CRU REGENERATION (continued)

Design	APC System	Sample location	Type	Substance	Data Source	Factor (lb/mm bbl)
Semi-Regenerative	CS	CS Outlet	Controlled	Lead	Test	3.03e-07
Semi-Regenerative	CS	CS Outlet	Controlled	Manganese	Test	7.82e-03
Semi-Regenerative	CS	CS Outlet	Controlled	Mercury	Test	1.90e-08
Semi-Regenerative	CS	CS Outlet	Controlled	Nickel	Test	3.27e-06
Semi-Regenerative	VSA	VSA Outlet	Controlled	Nickel	ICR	3.50e-02
Semi-Regenerative	VSA	VSA Outlet	Controlled	Nickel	ICR	3.50e-02
Semi-Regenerative	VSA	VSA Outlet	Controlled	Nickel	ICR	4.90e-02
Cyclic	SCS	SCS Outlet	Controlled	Chlorine	114	2.58e-01
Continuous	None	Regen Outlet	Uncontrolled	Chlorine	114	4.40e-01
Continuous	None	Regen Outlet	Uncontrolled	Chlorine	SV	4.50e-01
Continuous	None	Regen Outlet	Uncontrolled	Chlorine	114	6.00e-01
Continuous	na	Heater Outlet	Controlled	Chlorine	Test	1.41e+01
Continuous	None	Regen Outlet	Uncontrolled	Chlorine	114	1.46e+01
Semi-Regenerative	None	Regen Outlet	Uncontrolled	Chlorine	ICR	8.20e+01
Continuous	None	Regen Outlet	Uncontrolled	Chlorine	114	9.30e+01
Continuous	None	Regen Outlet	Uncontrolled	Chlorine	114	1.16e+02
Continuous	None	Regen Outlet	Uncontrolled	Chlorine	ICR	1.75e+02
Continuous	None	Regen Outlet	Uncontrolled	Chlorine	114	1.83e+02
Continuous	PC	Regen Outlet	Uncontrolled	Chlorine	114	4.08e+02
Cyclic	SCS/Flare	Regen Outlet	Uncontrolled	HCl	114	3.10e-02
Semi-Regenerative	CS	CS Outlet	Controlled	HCl	Test	5.77e-02
Cyclic	PS	Regen Outlet	Uncontrolled	HCl	114	1.00e-01
Cyclic	SCS/Flare	Flare Outlet	Controlled	HCl	114	1.50e-01
Cyclic	None	Regen Outlet	Uncontrolled	HCl	114	1.41e+00
Cyclic	None	Regen Outlet	Uncontrolled	HCl	114	3.24e+00
Cyclic	SCS	SCS Outlet	Controlled	HCl	114	4.00e+00
Cyclic	SCS/Flare	Regen Outlet	Uncontrolled	HCl	114	2.51e+01
Continuous	PC	Regen Outlet	Uncontrolled	HCl	114	2.71e+01
Continuous	None	Regen Outlet	Uncontrolled	HCl	114	3.40e+01
Cyclic	None	Regen Outlet	Uncontrolled	HCl	114	4.49e+02
Cyclic	None	Regen Outlet	Uncontrolled	HCl	114	4.49e+02
Semi-Regenerative	None	Regen Outlet	Uncontrolled	HCl	ICR	4.52e+02
Continuous	None	Regen Outlet	Uncontrolled	HCl	SV	5.40e+02
Cyclic	None	Regen Outlet	Uncontrolled	HCl	114	5.75e+02
Continuous	None	Regen Outlet	Uncontrolled	HCl	114	6.71e+02
Continuous	None	Regen Outlet	Uncontrolled	HCl	114	7.52e+02
Continuous	None	Regen Outlet	Uncontrolled	HCl	114	7.89e+02
Continuous	None	Regen Outlet	Uncontrolled	HCl	114	9.42e+02
Cyclic	None	Regen Outlet	Uncontrolled	HCl	114	1.12e+03
Cyclic	None	Regen Outlet	Uncontrolled	HCl	114	1.14e+03

TABLE B-2. EMISSIONS DATA FOR CRU REGENERATION (continued)

Design	APC System	Sample location	Type	Substance	Data Source	Factor (lb/mm bbl)
Continuous	None	Regen Outlet	Uncontrolled	HCl	ICR	1.24e+03
Continuous	na	Heater Outlet	Uncontrolled	HCl	Test	2.17e+03
Cyclic	None	Regen Outlet	Uncontrolled	HCl	114	2.39e+03
Continuous	None	Regen Outlet	Uncontrolled	HCl	114	3.16e+03
Continuous	None	Regen Outlet	Uncontrolled	HCl	114	3.60e+03
Continuous	None	Regen Outlet	Uncontrolled	HCl	114	3.97e+03
Cyclic	None	Regen Outlet	Uncontrolled	HCl	114	8.43e+03
Semi-Regenerative	CS	CS Outlet	Controlled	4F 2378	Test	8.64e-12
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	4F 2378	Test	3.84e-10
Semi-Regenerative	CS	CS Outlet	Controlled	4F Total	Test	8.64e-12
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	4F Total	Test	1.50e-09
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	4F Total	Test	4.48e-09
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	5D 12378	Test	2.23e-10
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	5D Total	Test	5.89e-10
Semi-Regenerative	CS	CS Outlet	Controlled	5F 12378	Test	1.49e-11
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	5F 12378	Test	1.79e-10
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	5F 12378	Test	7.75e-10
Semi-Regenerative	CS	CS Outlet	Controlled	5F 23478	Test	1.10e-11
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	5F 23478	Test	3.53e-10
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	5F 23478	Test	1.81e-09
Semi-Regenerative	CS	CS Outlet	Controlled	5F Total	Test	6.10e-11
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	5F Total	Test	2.38e-09
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	5F Total	Test	8.48e-09
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	6D 123478	Test	1.98e-10
Semi-Regenerative	CS	CS Outlet	Controlled	6D 123789	Test	5.78e-12
Semi-Regenerative	CS	CS Outlet	Controlled	6D Total	Test	1.25e-11
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	6D Total	Test	4.60e-10
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	6D Total	Test	2.13e-09
Semi-Regenerative	CS	CS Outlet	Controlled	6F 123478	Test	2.91e-11
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	6F 123478	Test	3.96e-10

TABLE B-2. EMISSIONS DATA FOR CRU REGENERATION (continued)

Design	APC System	Sample location	Type	Substance	Data Source	Factor (lb/mm bbl)
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	6F 123478	Test	1.75e-09
Semi-Regenerative	CS	CS Outlet	Controlled	6F 123678	Test	2.91e-11
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	6F 123678	Test	5.30e-10
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	6F 123678	Test	1.78e-09
Semi-Regenerative	CS	CS Outlet	Controlled	6F 234678	Test	1.13e-11
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	6F 234678	Test	1.04e-09
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	6F 234678	Test	2.05e-09
Semi-Regenerative	CS	CS Outlet	Controlled	6F Total	Test	5.15e-11
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	6F Total	Test	3.93e-09
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	6F Total	Test	1.30e-08
Semi-Regenerative	CS	CS Outlet	Controlled	7D 1234678	Test	9.45e-12
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	7D 1234678	Test	6.35e-10
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	7D 1234678	Test	1.16e-09
Semi-Regenerative	CS	CS Outlet	Controlled	7D Total	Test	1.90e-11
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	7D Total	Test	1.02e-09
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	7D Total	Test	2.30e-09
Semi-Regenerative	CS	CS Outlet	Controlled	7F 1234678	Test	1.37e-11
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	7F 1234678	Test	1.54e-09
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	7F 1234678	Test	4.87e-09
Semi-Regenerative	CS	CS Outlet	Controlled	7F 1234789	Test	9.73e-12
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	7F 1234789	Test	9.19e-10
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	7F 1234789	Test	1.38e-09
Semi-Regenerative	CS	CS Outlet	Controlled	7F Total	Test	2.22e-11
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	7F Total	Test	2.87e-09
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	7F Total	Test	8.10e-09
Semi-Regenerative	CS	CS Outlet	Controlled	8D	Test	1.99e-11
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	8D	Test	4.23e-09

Design	APC System	Sample location	Type	Substance	Data Source	Factor (lb/mm bbl)
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	8D	Test	4.45e-09
Semi-Regenerative	CS	CS Outlet	Controlled	8F	Test	1.86e-11
Semi-Regenerative	CI\Flare	CI Outlet	Controlled	8F	Test	7.86e-10
Semi-Regenerative	CI\Flare	Regen Outlet	Uncontrolled	8F	Test	1.67e-09
Semi-Regenerative	VSA	VSA Outlet	Controlled	Total PCDD	ICR	3.00e-09
Semi-Regenerative	VSA	VSA Outlet	Controlled	Total PCDD	ICR	3.10e-09
Semi-Regenerative	VSA	VSA Outlet	Controlled	Total PCDD	ICR	4.20e-09
Semi-Regenerative	VSA	VSA Outlet	Controlled	Total PCDF	ICR	2.10e-08
Semi-Regenerative	VSA	VSA Outlet	Controlled	Total PCDF	ICR	3.00e-08
Semi-Regenerative	VSA	VSA Outlet	Controlled	Total PCDF	ICR	2.20e-02

APC = air pollution control
C = cyclone
CI = caustic injection
CS = caustic scrubber
I = incinerator
ICR = information collection request
lb/mm bbl = pounds per million barrels
NA = not available
PC = packed column
PCDD = polychlorinated dibenzo-p-dioxins
PCDF = polychlorinated dibenzofurans
PH = process heater
PS = plate and spray
SCS = spray circulating solution
ST = spray tower
VRS = vortex scrubber
VS = venturi scrubber
WHB = waste heat boiler
114 = section 114 request
4D - 8D = chlorodibenzo-p-dioxins (tetra- through octa-)
4F - 8F = chlorodibenzofurans (tetra- through octa-)

Table B-3. HAP Emission Data for SRU Plant Vent

HAP	Facility ID	Vent Number	Vent Description	Tailgas Type	APCD 1	SRU Prod. Rate (tpd)	HAP Emissions (tpy)	HAP Emissions (lb/1,000 ton)	Data Source
ACETALDEHYDE	27702	VENT 1	CLAUS		Incinerator		0.0012		ICR assume conc in ppm
FORMALDEHYDE	27702	VENT 1	CLAUS		Incinerator		0.0080		ICR assume conc in ppm
TOTAL HAP (all SRUs)	27702						0.0092		
FORMALDEHYDE	27701	VENT 1	CLAUS		Incinerator		4.7E-08		ICR assume conc in ppm
CYANIDE COMPD	27701	VENT 1	CLAUS		Incinerator		4.2E-10		ICR assume conc in ppm
ACETALDEHYDE	27701	VENT 1	CLAUS		Incinerator		7.6E-10		ICR assume conc in ppm
FORMALDEHYDE	27701	VENT 3	CLAUS		Incinerator		4.7E-08		ICR assume conc in ppm
CYANIDE COMPD	27701	VENT 3	CLAUS		Incinerator		4.2E-10		ICR assume conc in ppm
ACETALDEHYDE	27701	VENT 3	CLAUS		Incinerator		7.6E-10		ICR assume conc in ppm
FORMALDEHYDE	27701	VENT 4	CLAUS		Incinerator		0.0221		ICR assume conc in ppm
CYANIDE COMPD	27701	VENT 4	CLAUS		Incinerator		0.0150		ICR assume conc in ppm
ACETALDEHYDE	27701	VENT 4	CLAUS		Incinerator		0.0027		ICR assume conc in ppm
TOTAL HAP (all SRUs)	27701						0.0399		
BENZENE	20501	VENT 1	SULFUR			247.5	0.003	0.07	114 Response
CARBON DISULFIDE	20501	VENT 1	SULFUR			247.5	0.50	11.07	114 Response
CARBONYL SULFIDE	20501	VENT 1	SULFUR			247.5	0.80	17.71	114 Response
FORMALDEHYDE	20501	VENT 1	SULFUR			247.5	0.011	0.24	114 Response
TOLUENE	20501	VENT 1	SULFUR			247.5	0.002	0.04	114 Response
TOTAL HAP	20501	VENT 1	SULFUR			247.5	1.32	29.14	114 Response
CARBON DISULFIDE	J	VENT 3	CLAUS/TGCU			357.5	0.018	0.28	114 Response
CARBONYL SULFIDE	J	VENT 3	CLAUS/TGCU			357.5	1.43	22.0	114 Response
TOTAL HAP (all SRUs)	J						1.5	22.2	
CARBONYL SULFIDE	20701	Vent 1		Unspec.TGT	Incinerator	132	0.15	6.14	D. Hathaway (1993
CARBONYL SULFIDE	20701	Vent 2		Unspec.TGT	Incinerator	132	2.67	110.7	SourceTest - Sulfur
CARBONYL SULFIDE	20701	Vent 3		Unspec.TGT	Incinerator	132	2.37	98.4	Production Rate
CARBONYL SULFIDE	20701	Vent 4		Unspec.TGT	Incinerator	132	0.33	13.8	from Site
CARBONYL SULFIDE	20701	Vent 5		Unspec.TGT	Incinerator	132	1.35	55.9	Visit Data)
TOTAL HAP (all SRUs)	20701						6.86	285	
CARBONYL SULFIDE	20604	VENT 3	SULFUR PLANT		Incinerator	225	3.5	85.2	114 Response
CARBONYL SULFIDE	20604	VENT 4	SULFUR PLANT		Incinerator	225	3.5	85.2	114 Response
TOTAL HAP (all SRUs)	20604						7.0	170.5	
CARBONYL SULFIDE	G	VENT 5	SCU2/TGCU			1485	13.6	50.18	114 Response
CARBON DISULFIDE	F	VENT 10	SRU 1/2	Tail gas	Incinerator	55	0.39	38.9	114 Response
CARBONYL SULFIDE	F	VENT 10	SRU 1/2	Tail gas	Incinerator	55	1.42	141.5	114 Response
CARBONYL SULFIDE	27903	VENT 1	CLAUS		Incinerator		21.7		ICR
CARBONYL SULFIDE	28103	VENT 1	CLAUS -	BEAVON			16.32		ICR
CARBON DISULFIDE	28103	VENT 1	CLAUS -	BEAVON			0.20		ICR
CARBONYL SULFIDE	28103	VENT 2	CLAUS -	BEAVON			6.97		ICR
CARBON DISULFIDE	28103	VENT 2	CLAUS -	BEAVON			0.28		ICR
CARBONYL SULFIDE	28103	VENT 3	CLAUS -	BEAVON			24.34		ICR
CARBON DISULFIDE	28103	VENT 3	CLAUS -	BEAVON			0.20		ICR
TOTAL HAP (all SRUs)	28103						48.30		

Table B-3. HAP Emission Data for SRU Plant Vent

HAP	Facility ID	Vent Number	Vent Description	Tailgas Type	APCD 1	SRU Prod. Rate (tpd)	HAP Emissions (tpy)	HAP Emissions (lb/1,000 ton)	Data Source
CARBONYL SULFIDE	28282			Unpec.TGT			50.0		D Hathaway-all SRU vents
CARBON DISULFIDE	29403	VENT 1	CLAUS	BEAVON			244		ICR *assume conc in ppm*
CARBONYL SULFIDE	29403	VENT 1	CLAUS	BEAVON			15.1		ICR *assume conc in ppm*
CARBON DISULFIDE	29403	VENT 2	CLAUS	BEAVON			312		ICR *assume conc in ppm*
CARBONYL SULFIDE	29403	VENT 2	CLAUS	BEAVON			16.3		ICR *assume conc in ppm*
CARBON DISULFIDE	29403	VENT 3	STRETFORD		Incinerator		0.21		ICR *assume conc in ppm*
CARBONYL SULFIDE	29403	VENT 3	STRETFORD		Incinerator		1.06		ICR *assume conc in ppm*
TOTAL HAP (all SRUs)	29403						589		