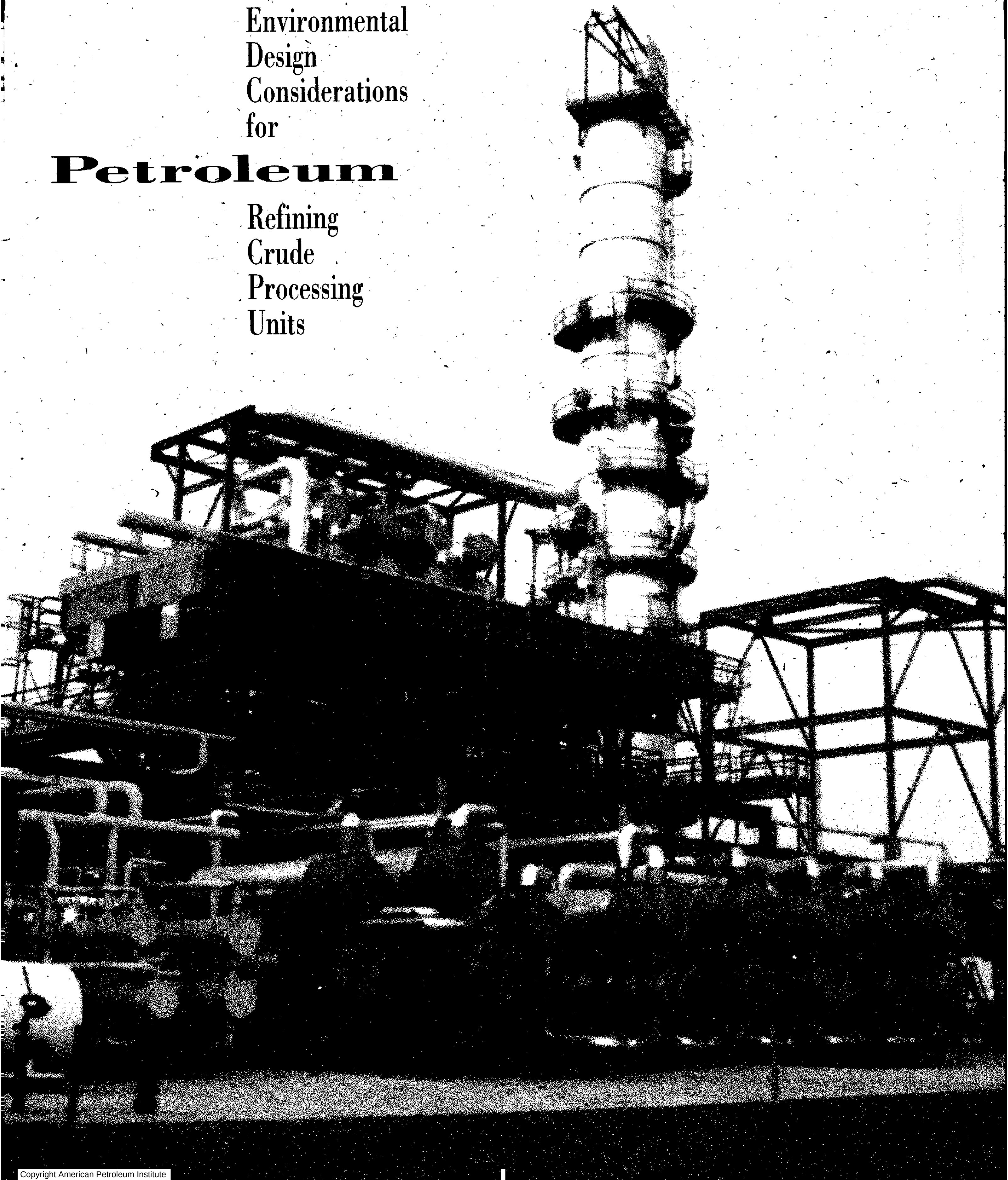
Environmental Design Considerations for **Petroleum** Refining Crude Processing Units



Environmental Design Considerations for Petroleum Refining Crude Processing Units

Health and Environmental Affairs Department

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ENVIRONMENTAL DESIGN CONSIDERATIONS FOR PETROLEUM REFINING CRUDE PROCESSING UNITS

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Section 1: EXECUTIVE SUMMARY

1.1 Basis of Study

The Pollution Prevention Task Force (PPTF) of the American Petroleum Institute (API) has developed the following working definition of pollution prevention:

> "Pollution prevention is a multi-media concept that reduces or eliminates pollutant discharges to air, water, or land and includes the development of more environmentally acceptable products, changes in processes and practices, source reduction, beneficial use and environmentally sound recycling."

The PPTF and the API Committee on Refinery Environmental Control (CREC) recognize the importance of developing pollution prevention strategies for refineries. This study was initiated to investigate how the crude unit in a typical refinery could be designed to minimize multi-media environmental releases while still efficiently performing the traditional functions of a crude unit.

This report presents the findings of the study. The report is intended to serve as a reference for refinery designers during the preliminary design phase of building a new crude unit or revamping an existing crude unit.

A generic methodology for conducting pollution prevention studies on process units was developed and was then applied to the refinery crude unit (refer to Section 4). This methodology approched pollution prevention from two perspectives, or cases:

Case 1 -	The design of a model new crude unit.
Case 2 -	The revamp of a conventional existing crude unit, applying the principles learned in Case 1.

A typical ten-year-old U.S. Gulf Coast crude unit of 175,000 BPSD capacity was chosen to serve as the reference point or Base Case.

The technical contents of this report include: crude charge and product slates, process flow diagrams, major equipment lists, raw material use, water use, energy, equipment costs, and multi-media releases. These releases include: point source air emissions, fugitive air emissions, solid and hazardous waste production, and wastewater inventory.

The study investigated in detail these specific methods of pollution prevention:

- modification of vacuum tower to dry operation and reduced flash zone pressure to minimize cracking of feed;
- dry operation to reduce the quantity of sour condensate;
- use of vacuum pumps to replace all or part of the steam jet ejector system to provide the vacuum for the vacuum tower;
- use of reboiled sidestrippers on the atmospheric tower rather than open steam stripping to reduce the quantity of sour condensate;
- replacement of first generation low NO_x burners with new generation low NO_x burners in furnaces;
- use of catalytic and non-catalytic processes for the selective reduction of NO_x;
- reuse of stripped sour water to replace clean process water as desalter water; and

- heat integration for maximum energy utilization (commonly referred to as pinch analysis).

1.2 Limitations of Study Results

Numerous pollution prevention concepts have been evaluated and reported in this study, but no optimum or "best" design is implied. This study was as comprehensive as time allowed, but doubtlessly there are other pollution prevention measures that have potential application to crude units. Each refiner will need to make an assessment of his refinery's requirements and then consider the ideas that best suit those needs. Corporate planning, engineering, regulatory, and operations personnel will be able to use the ideas and techniques reported in this study as an initial step toward a more thorough case-by-case evaluation of pollution prevention for the crude units at individual refineries.

1.3 Pollution Prevention Ideas for Model New Crude Unit

For a model new crude unit (Case 1), the following pollution prevention ideas may be considered in the design stage and are reported in Section 6:

- Apply pinch analysis to the crude preheat train heat integration (refer to Appendix I). Increase crude preheat temperature and minimize heat losses to air and cooling water.

- Increase crude distillation column pumparounds from two to four. Reboil sidestrippers with a heat transfer oil rather than by steam stripping.

- Lower vacuum column flash zone pressure from 35 to 20 mmHgabs. This will lower furnace fired duty and reduce cracking of the feed to lighter products and wet oil/recovered oil.

- Use a liquid ring vacuum pump in place of the third stage steam jet ejector on the vacuum tower overhead.

- Strip desalter brine for benzene removal before sending brine to wastewater treatment. Send recovered benzene to gasoline blending.

- Install new generation low NO_x burners. Use selective catalytic reduction (SCR) to reduce NO_x in furnace flue gas.

- Scrub furnace flue gas for removal of SO_x when firing high sulfur fuel oil.

- Optimize water reuse by application of sidestream softening to blowdown streams.

- Apply advanced process control to optimize energy utilization. Install analyzers to provide continuous pollutant monitoring.

- Employ specialized hardware and inspection & maintenance (I&M) to eliminate fugitive emissions of volatile organic compounds (VOC):
    - Select leakless or graphite packed valves.
    - Use sealless design pumps or pumps with double seals.
    - Minimize flanges and install sealing rings on leaking flanges.
    - Blind, plug, or cap open-ended vent and drain valves.

- Route relief valves to flare and add rupture disks.

- Pipe compressor seal vents back to process and vent compressor distance pieces to refinery flare.

- Install a maintenance drain-out (MDO) system to eliminate open discharges from drains.

- Totally close-loop all samplers.

1.4 Pollution Prevention Ideas for Revamp of Conventional Crude Unit

For the revamp of an existing conventional crude unit (Case 2), the following pollution prevention ideas may be considered and are reported in Section 7:

- Apply pinch analysis to the crude preheat train heat integration. Increase crude preheat temperature and minimize heat losses to air and cooling water. Keep equipment and piping relocation to a manageable minimum.

- Reboil the atmospheric column sidestrippers (except for high boiling point Atmospheric Gas Oil) with heat transfer oil rather than by steam stripping. Install two new sidestrippers and modify one existing sidestripper.

- Lower vacuum column flash zone pressure from 35 to 20 mmHgabs. Use liquid ring vacuum pump in place of the third stage steam jet ejector on the vacuum tower overhead. Add parallel ejectors to the first and second stages.

- Strip desalter brine for benzene removal.

- Retrofit new generation low NO_x burners and install SCR units for post-combustion NO_x reduction.

- Scrub flue gas for removal of SO_x when firing high sulfur fuel oil in heaters.

- Optimize water reuse by application of sidestream softening to blowdown streams.

- Apply advanced process control to optimize energy utilization. Install analyzers to provide continuous pollutant monitoring.

- Employ specialized hardware and I&M to reduce fugitive emissions of VOC:

    - Improve I&M program (leak definition, monitoring frequency, and repair response time).

    - Selectively retrofit leakless or graphite packed valves.

    - Selectively retrofit sealless design pumps or pumps with double seals.

    - Minimize flanges and install sealing rings on leaking flanges.

    - Blind, plug, or cap open-ended vent and drain valves.

    - Route relief valves to flare and/or add rupture disks.

- Pipe compressor seal vents back to process and vent compressor distance pieces to refinery flare.
- Install a MDO system to eliminate open discharges from drains.
- Totally close-loop all samplers.

1.5 Summary of Findings

Air emissions, wastewater effluents, solid wastes, energy consumption, and costs are summarized in Table 1.1. Figures 1.1 through 1.4 give graphical representations of air emissions, wastewater loads, and solid waste generation.

The findings of this pollution prevention study on refinery crude units are summarized below:

- A generic systematic methodology for conducting pollution prevention studies on process units can be applied to the crude unit in a typical refinery.
- There is a correlation between energy efficiency and environmental effectiveness: the more efficient the crude unit, the less it pollutes.
- The total energy usage in the crude unit can be reduced by improving heat integration in the crude preheat train through pinch analysis.
- Reductions in wastewater generation can be achieved by energy reduction and stream recycling.

- Reductions in solid and hazardous wastes can be achieved by water recycling and preventing the mixing of hazardous and non-hazardous waste streams. If the heaters burn high sulfur fuel, limestone scrubbing for SO_x reduction will generate non-hazardous sludge.

- NO_x emissions can be reduced by new generation low NO_x burners, SCR units, and Flue Gas Recirculation (FGR).

- The total annual benzene quantity (TAB) in wastewater can be reduced by steam stripping.

- Fugitive emissions from piping components can be reduced by hardware improvements and stringent inspection & maintenance programs.

TABLE 1.1: SUMMARY OF FINDINGS
MULTI-MEDIA RELEASES FROM 175,000 BPSD CRUDE UNIT

HEATERS FIRING FUEL GAS

	AIR EMISSIONS, TON/YR					WASTE WATER, GPM	SOLID WASTE, TONS/DAY		ENERGY		
	NO_x	CO	VOC	TSP	SO_x		HAZARDOUS	NON-HAZARDOUS	MMBTU/ HR	KW	CAPITAL COST $MM
BASE CASE (Conventional Crude Unit)	415	185	183	23	3.3	584	6.3	0	948	2,670	128.7
CASE 1 (Model New Crude Unit)	164	152	5.6	19	2.7	339	0.5	2.7	786	3,153	164.3
Reductions (Base Case - Case 1)	251	33	177	4	0.6	245	5.8	-2.7	162	-483	-35.6
CASE 2 (Revamp of Conventional Crude Unit)	170	168	12	21	3.0	342	0.5	3.7	864.5	3,033	28.7
Reductions (Base Case - Case 2)	245	17	171	2	0.3	242	5.8	-3.7	83.5	-363	n/a

CRUDE HEATER FIRING 1 wt% SULFUR FUEL OIL

	AIR EMISSIONS, TON/YR					WASTE WATER, GPM	SOLID WASTE, TONS/ DAY		ENERGY		
	NO_x	CO	VOC	TSP	SO_x		HAZARDOUS	NON-HAZARDOUS	MMBTU/ HR	KW	CAPITAL COST $MM
BASE CASE (Conventional Crude Unit)	597	171	190	187	2,105	584	6.3	0	948	2,670	128.7
CASE 1 (Model New Crude Unit)	172	142	11	134	149	339	0.5	12.5	786	3,310	169.8
Reductions (Base Case - Case 1)	425	29	179	53	1,956	245	5.8	-12.5	162	-640	-41.1
CASE 2 (Revamp of Conventional Crude Unit)	179	156	18	157	176	342	0.5	15.3	864.5	3,190	34.7
Reductions (Base Case - Case 2)	418	15	172	30	1,929	242	5.8	-15.3	83.5	-520	n/a

FIGURE 1.1
AIR EMISSIONS FROM 175,000 BPSD CRUDE UNIT
(HEATERS FIRING FUEL GAS)

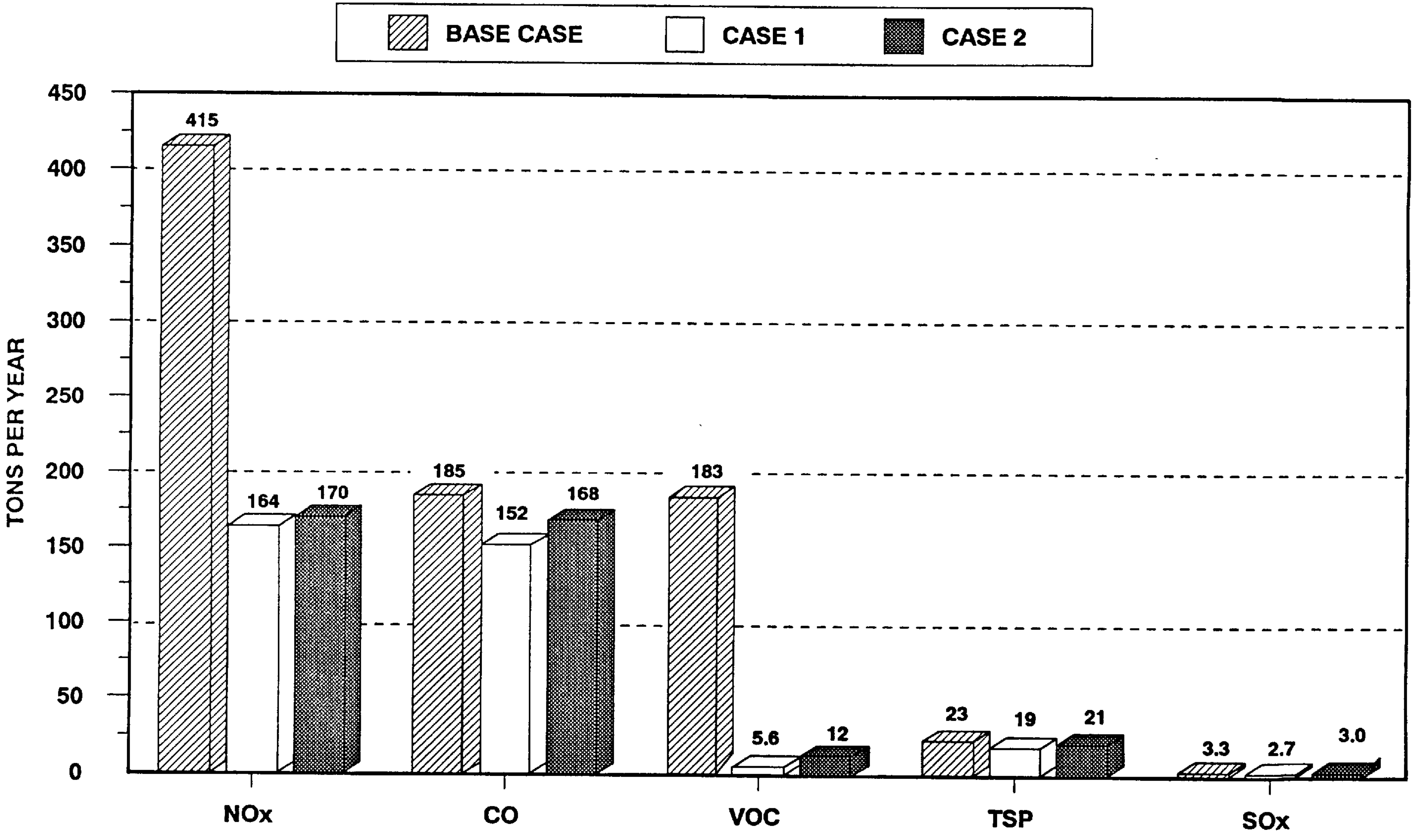


FIGURE 1.2
AIR EMISSIONS
FROM 175,000 BPSD CRUDE UNIT
(ATMOSPHERIC CRUDE HEATER FIRING 1 WT% SULFUR FUEL OIL)

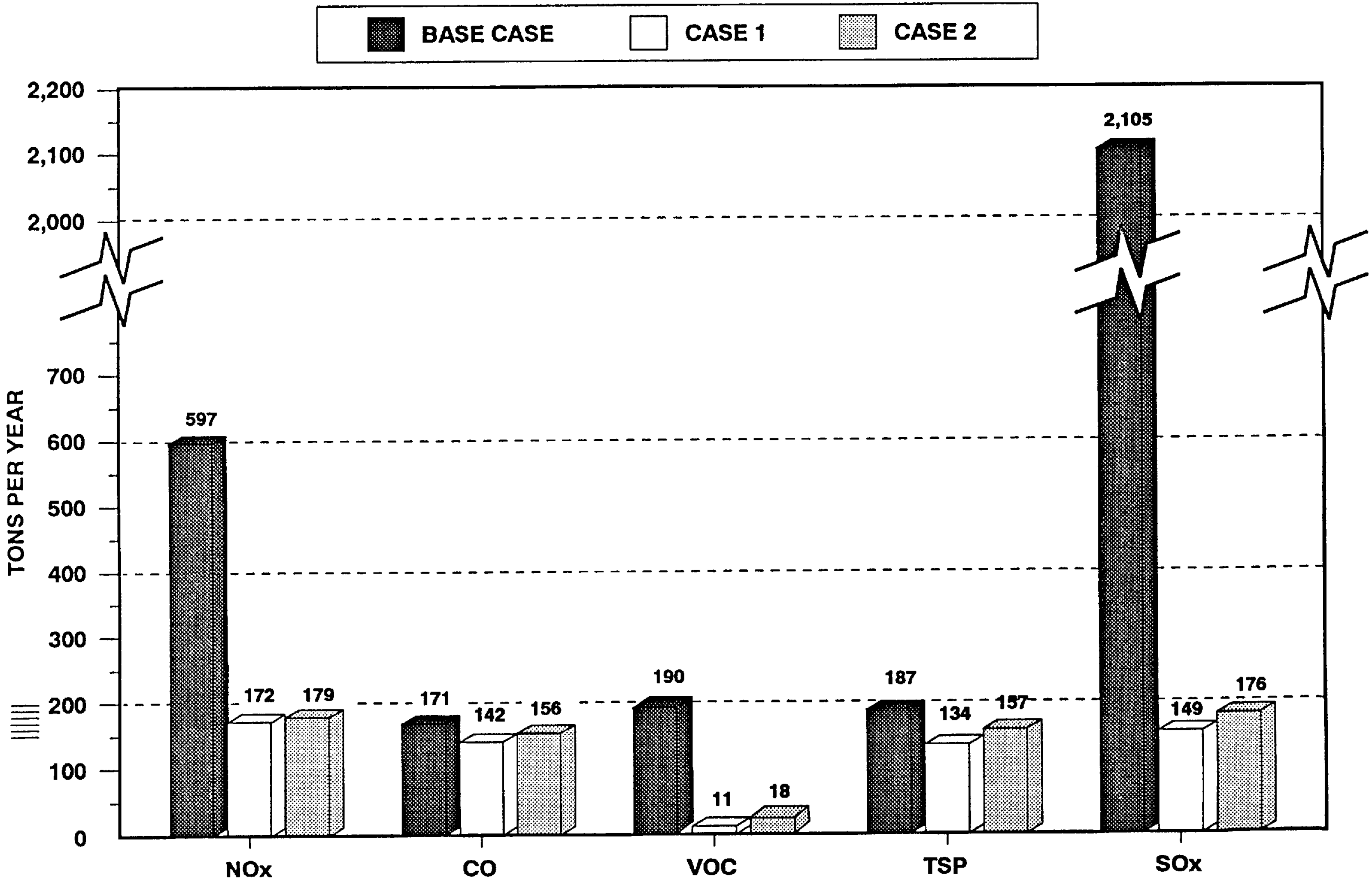


FIGURE 1.3

WASTE WATER LOADS FROM 175,000 BPSD CRUDE UNIT

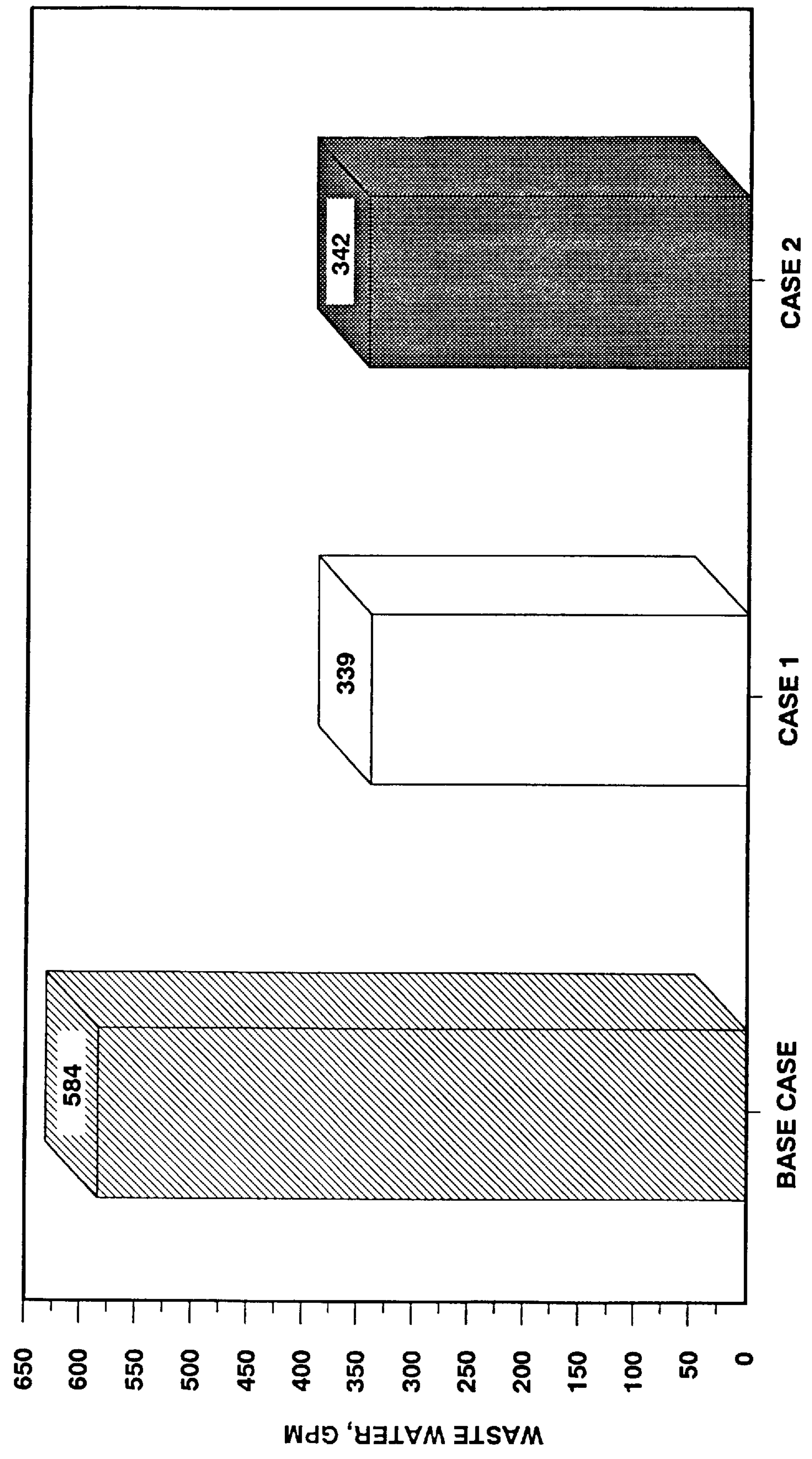
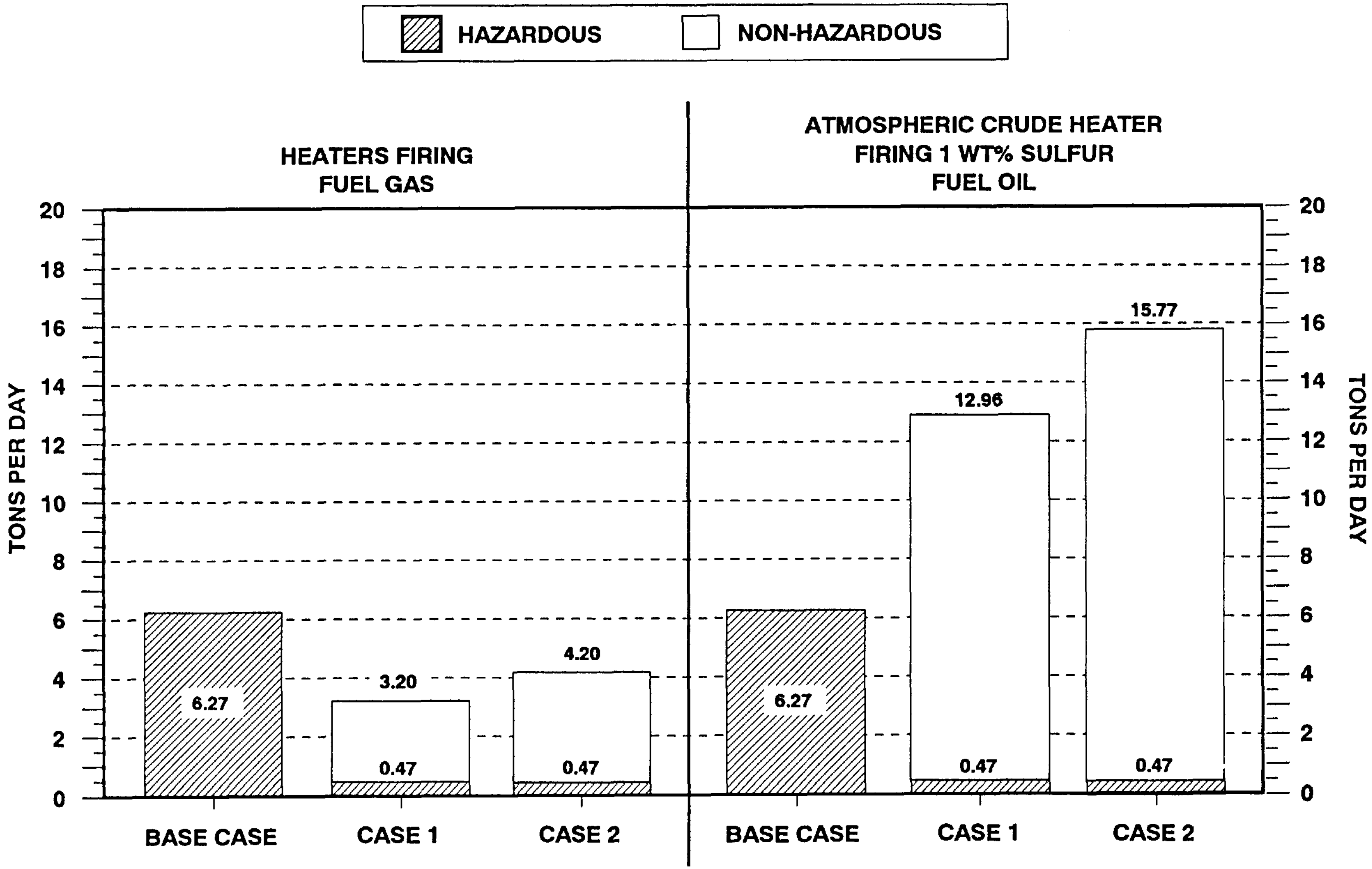


FIGURE 1.4

SOLID WASTE GENERATION FROM 175,000 BPSD CRUDE UNIT



Section 2: INTRODUCTION

2.1 Background

API has developed the following working definition of pollution prevention:

> "Pollution prevention is a multi-media concept that reduces or eliminates pollutant discharges to air, water, or land and includes the development of more environmentally acceptable products, changes in processes and practices, source reduction, beneficial use and environmentally sound recycling."

The API definition of pollution prevention does not include end-of-the-pipe treatment. With this definition serving as the theme, the API Pollution Prevention/CREC Workgroup initiated this pollution prevention study on crude units.

2.2 Statement of Objective

The objective of this study was to investigate how the crude unit in a "typical" refinery could minimize multi-media releases while still efficiently performing the traditional functions of a crude unit. Consistent with good engineering practice, both pollution prevention and end-of-the-pipe treatment approaches were considered.

2.3 Study Plan

This study viewed pollution prevention from two perspectives:

- from the point of view of designing a model new crude unit (referred to as Case 1); and
- from the point of view of revamping a conventional existing crude unit (referred to as Case 2).

To serve as a reference point or Base Case, a typical ten-year-old U.S. Gulf Coast crude unit of 175,000 BPSD feed rate was chosen.

2.4 Usefulness of Results

The primary result of this study is a technical assessment of alternative pollution prevention concepts applicable to a refinery crude unit and how these concepts could be incorporated into a new or revamp crude unit. A secondary product of the study is the methodology that was developed for the systematic analysis of pollution prevention. This methodology is applicable to the evaluation of other refinery processes and to individual pollution prevention projects.

Some caveats apply to this study. This study should not be regarded as a recommendation for the process design of a crude unit. Only one type of crude and one set of product specifications were considered in this study. This does not form an adequate design basis for a process study. Multiple crude feedstocks and a range of product specifications would normally be considered in the design of a crude unit.

2.5 Limitations of Study Results

No optimum or "best" design is to be implied from this study. Numerous pollution prevention concepts have been evaluated and reported in this study. Other pollution prevention measures have potential application to crude units. Each refiner will need to make an assessment of requirements and utilize the ideas and concepts that best fit the needs of the individual refinery and situation. Corporate planning, engineering, regulatory, and operations personnel will be able to use the ideas and techniques developed by this study as an initial step toward a more thorough case-by-case evaluation of pollution prevention at individual refineries.

There is considerable difference between a conceptual study and the actual implementation of pollution prevention systems. For many of the ideas that appear to be promising for an individual refinery, it may be necessary to conduct laboratory studies or field demonstrations before implementing the project.

Laboratory studies are useful to verify the technical feasibility of the proposed design and operating changes, to confirm that the process will still produce products that meet customer requirements, to develop a basis for investment estimates, and to identify safety and logistic concerns prior to field implementation. Plant field demonstrations prove the technology on a larger scale.

2.6 Physical Boundaries and Study Limits

The scope and content of this study was limited to the crude unit and subject to the boundaries and exclusions explained below:

2.6.1 The study addressed equipment and processes Inside Battery Limits (ISBL) of the crude unit, including:

- crude oil desalter
- crude oil preheat exchangers
- atmospheric distillation tower and its heater
- vacuum-producing equipment
- vacuum distillation tower and its heater.

2.6.2 A single sour crude feedstock was chosen: Light Arabian Crude.

2.6.3 Compression of overhead vapors from the atmospheric tower was accomplished within the battery limits.

2.6.4 The stabilizer was not within the study scope.

2.6.5 Unstabilized naphtha was routed to the battery limits for further processing.

2.6.6 The study investigated in detail the following methods of pollution prevention:

- modification of vacuum tower to dry operation and reduced flash zone pressure to minimize cracking of feed;
- dry operation to reduce the quantity of sour condensate;
- use of vacuum pumps to replace all or part of the steam jet ejector system used to create the vacuum for the vacuum tower;
- use of reboiled side strippers on the atmospheric tower rather than open steam stripping to reduce the quantity of sour condensate;
- replacement of conventional burners with low NO_x burners in furnaces;
- use of catalytic and non-catalytic processes for the selective reduction of NO_x;
- reuse of stripped sour water to replace clean steam condensate as desalter water; and
- heat integration for maximum energy utilization.

Other methods for pollution prevention were subsequently added or substituted for the ones mentioned above as the study evolved.

2.7 Future Studies

During the execution of this study, several areas were identified as worthy of further analysis in a future study:

- Analysis of interfaces with other refinery process units for downstream impacts
- Evaluation of alternate crude and product slates

- Sensitivity analysis of other engineering and financial parameters

- Evaluation of cooling tower system

2.8 Overview of This Report

Section 1	Executive Summary This section summarizes the findings of the study.
Section 2	Introduction This section previews the contents of this report and explains the basis for the study.
Section 3	Regulatory Issues This section discusses the environmental regulations currently driving refineries and their influence on pollution prevention.
Section 4	Methodology This section describes a generic methodology for conducting pollution prevention studies and how this methodology was applied to the pollution prevention study for crude oil units.
Section 5	Conventional Crude Unit (Base Case) This section presents the results of a process and environmental audit of a conventional existing crude unit, referred to as the Base Case.
Section 6	Model New Crude Unit (Case 1) This section describes a conceptual design for a model new crude unit which incorporates practicable pollution prevention ideas. The Model New Crude Unit is referred to as Case 1.

Section 7 Revamp of Conventional Crude Unit (Case 2)

This section describes how the Base Case crude unit can be revamped to incorporate pollution prevention ideas. The revamp of the conventional crude unit is referred to as Case 2.

Appendices A through M contain the collected information referenced in the text of the report.

Section 3: REGULATORY ISSUES

3.1 General Issues

Environmental regulatory compliance for today's petroleum refinery is an ever-increasing economic, technical, and operational challenge. Some of the most important environmental statutes that apply to U.S. refineries are:

- The Clean Air Act (CAA)
- The Clean Water Act (CWA)
- The Resource Conservation and Recovery Act (RCRA)
- The Superfund Amendments and Reauthorization Act (SARA)
- The Pollution Prevention Act of 1990 (PPA)

Several of these statutes that have been enacted or amended in the recent past contain various components of pollution prevention. Moreover, the Clinton administration has indicated that pollution prevention will continue to be a priority of the Environmental Protection Agency in its future activities.

In addition to traditional regulatory initiatives, pollution prevention (and energy efficiency) have also become the focus of many non-regulatory initiatives such as the 33/50 Program and the Green Lights Program. A common element of these programs seeks to engage facilities and individual companies in determining their own levels of participation in such programs and in finding the most cost-efficient method of attaining broad environmental goals set by the Agency. Other voluntary efforts by industry trade associations (e.g., Responsible Care and STEP), independent organizations (GEMI), and company programs (e.g., SMART and WOW) are yet another method of instilling the pollution prevention principles into industry operations.

The result of the coupling of the traditional regulatory compliance activities and the numerous voluntary initiatives result in a very complex system and a close linkage between normal daily production operations and those systems installed to eliminate, separate, purify, recycle, and reuse refinery streams that might have otherwise become wastes. Additionally, refiners and the operators of individual process units within the refinery are becoming responsible for the wastes their units generate and the resulting costs and liabilities incurred for treatment and disposal of generated wastes. This new aspect of responsibility for waste generation at the unit operation level add a new indicator of refining production efficiency. In addition to barrels of product per barrel of feed crude to pounds of waste generated per barrel of crude feed.

Refiners have demonstrated a historic capability to modify operations and maintenance attitudes and procedures to meet process, safety and environmental requirements. As these capabilities continue to evolve, new process design tools coupled with the arrival of proven and economic technologies will allow the industry to continue its efforts in achieving and sometimes exceeding environmental regulations. This chapter describes components of the various environmental regulations that may apply to petroleum refining operations.

3.2 Air Emissions

3.2.1 Federal Programs

Air emissions from refineries are regulated by the state and the federal government. State air programs are administered by a state department of environmental quality, commission, board, or similar agency. State agencies may adopt more stringent emission standards than federal standards.

The federal program is administered by the United States Environmental Protection Agency (EPA)and authorized states under the CAA. The EPA has promulgated several emission standards and programs which affect new and existing refineries, including:

- New Source Performance Standards (NSPS)
- National Emission Standards For Hazardous Air Pollutants (NESHAP)
- Prevention of Significant Deterioration of Air Quality (PSD)
- Best Available Control Technology (BACT)
- Lowest Achievable Emission Rate (LAER)

NSPSs which can apply to the crude unit (ignoring for this analysis the offsite and utility support systems for the crude unit) and include:

- 40 CFR Part 60 Subpart A - General Provisions
- 40 CFR Part 60 Subpart J - Standards of Performance for Petroleum Refineries
- 40 CFR Part 60 Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries
- 40 CFR Part 60 Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems

NESHAPs which can apply to the crude unit include:

- 40 CFR Part 61 Subpart A - General Provisions
- 40 CFR Part 61 Subpart J - National Emission Standard for Equipment Leaks (Fugitive Emission Sources) Benzene
- 40 CFR Part 61 Subpart FF - National Emission Standard for Benzene Waste Operations
- 40 CFR Part 61 Subpart V - National Emission Standard for Equipment Leaks (Fugitive Emission Sources)

The PSD program requires existing refineries that make major modifications to air emission sources to apply BACT. In non-attainment areas (areas which exceed the national ambient air quality standard for an air pollutant), refineries are subject to LAER controls, which is a technology standard more stringent than BACT.

The Clean Air Act regulates both point source (stack) emissions and fugitive emissions. The species and quantity of both point source and fugitive emissions are also included in calculations and modeling for air permit applications. Stack and fugitive emissions are also regulated under PSD.

The NESHAP and NSPS rules are interrelated in that both regulate air emissions from process effluents and wastewater. For example, NSPS regulations (40 CFR 60 Subpart QQQ) regulate the air emissions of VOCs from new and modified wastewater treatment equipment and sewers. NESHAP standards (40 CFR 61 Subpart FF) regulate chemicals such as benzene in waste and wastewaters.

3.2.2 The Clean Air Act Amendments

The Clean Air Act Amendments (CAAA) of 1990 expanded the EPA's enforcement powers and added or revised restrictions on the air emissions containing toxic chemicals, stratospheric ozone-depleting chemicals, acid rain related oxides of nitrogen (NO_x) and sulfur (SO_x), and gases considered to cause global warming (CO_2). With respect to hazardous air pollutants, amended Section 112 requires EPA to develop technology-based standards for 189 chemicals for certain source categories (e.g., refineries and marketing facilities). Emissions reductions of up to 90 percent will be required depending on the category of chemicals and the total annual emissions from the plant. Such standards are to be based on what can be achieved by Maximum Achievable Control Technology (MACT).

Once emissions of hazardous air pollutants have been controlled with MACT, EPA will assess remaining risks and may require that additional controls be implemented.

Emissions limits for VOCs will have a significant impact on wastewater treatment systems. Because widely used emissions control technologies involve transfer of the contaminant to an aqueous medium (e.g., scrubbing), either the contaminant must be recovered and reused in the plant processes or it must be treated prior to discharge. Recovery and reuse qualifies under the EPA's source reduction definition, while treatment prior to discharge does not.

3.3 Wastewater Treatment And Discharges

3.3.1 Clean Water Act

Wastewater discharges from refineries are regulated by the state and the federal government.

State programs are administered by a state department of environmental quality, water commission, or similar agency.

The federal program is administered by the EPA under the authority of the Clean Water Act (CWA). Under the CWA, discharges to U.S. waters must have a permit. Permits must contain technology-based limits and where necessary, water quality limits.

Technology-based limits include:

- Best Practicable Control Technology Currently Available (BPT)
- Best Available Technology Economically Achievable (BAT)
- Best Conventional Pollutant Control Technology (BCT)
- New Source Performance Standards (NSPS)

Discharges who discharge publicly-owned treatment works must comply with general pretreatment regulation, and where applicable, categorical:

- Pretreatment Standards for Existing Sources (PSES), and
- Pretreatment Standards for New Sources (PSNS).

The effluent limitations corresponding to each control strategy can be found in the Code of Federal Regulations, Title 40 - Protection of Environment, Chapter I - Environmental Protection Agency, Subchapter N - Effluent Guidelines and Standards, Part 419 - Petroleum Refining Point Source Category.

Under 1987 amendments to the Clean Water Act, the EPA required all states to set standards limiting toxic chemical concentrations in aqueous discharges from Publicly Owned Treatment Works (POTWs) and NPDES discharges within their state by early 1992. This ruling now involves 105 chemicals and will include additional chemicals as time passes. Many states have not set these standards and will be subject to EPA enforcement.

Water quality-based permit limits must be met regardless of cost and feasibility and are based on water quality standards which states are to establish and revise periodically. State agencies may adopt more stringent wastewater discharge limits than the federal limits. Some states have set their own surface water quality standards and have recently adopted new limits for toxic chemicals. Recently, EPA promulgated water quality standards applicable in states that had failed to update their own (57 FR 60848; December 22, 1992).

3.4 RCRA Hazardous Waste

The 1984 Hazardous and Solid Waste Amendments to RCRA required EPA to define limitations to "wastes" intended for land disposal. This limitation was established for "listed" or "characteristic" hazardous wastes. One important ramification of these regulations is the change that will be required in the wastewater treatment facilities that receive waste streams now classified as hazardous wastes. For example, under current classification procedures, refinery wastewater containing 0.5 ppm benzene is characteristically hazardous. Surface impoundments "that manage wastes meeting the RCRA definition of hazardous" will have to meet the requirements of RCRA permitted facilities, including double liners, leachate collection systems, VOC control measures, and groundwater monitoring systems. Existing hazardous waste impoundments that manage wastes RCRA definition of hazardous must be retrofitted by March 29, 1994.

Another important environmental regulation promulgated by the EPA on November 2, 1990 and enacted on May 2, 1991 is the Refinery Primary Sludge Listing. This listing defines most sludges (designated F037 and F038) generated by refinery process wastewater systems as hazardous wastes. These separation operations include any portion of the process wastewater treatment system that generates sludges from the physical or chemical separation of oil, water, and solids. These operations are now designated as hazardous waste treatment facilities. These hazardous waste treatment facilities may require re-permitting under RCRA and must comply with Minimum Technical Standards by November 2, 1994, or cease generating any such sludges by that date.

3.5 The Pollution Prevention Act

The Pollution Prevention Act of 1990 (PPA) expanded the required SARA Title III Form R reporting to include reporting on the methods being used to reduce waste generation at the site, the amounts reduced for each type of waste and chemical, and the efforts underway to reduce wastes further. It is expected that this publicly available information will be reviewed closely by a number of special interest groups that are involved in public hearings and permitting activities for refiners. It is also expected that those companies who have achieved their predicted or promised waste reduction goals will be allowed greater ease of environmental permitting and new plant sitings.

3.5.1 Chemical Release Reporting

The purpose of the PPA is to establish a national policy to reduce or eliminate the generation of waste at the source, whenever feasible. The PPA directs the EPA to initiate an extensive program of information collection, technology transfer, and financial assistance to the states to implement this policy and to promote source reduction techniques.

Reporting data that must be included in each annual SARA III Form R are as follows:

- Annual quantities of each toxic chemical entering waste streams prior to off-site recycling, treatment, or disposal. This includes the percent change from the previous year and estimates for the next two years.

- Annual quantities of each chemical recycled on-site and off-site, the recycling processes used, the percentage change from the previous year, and estimates for the next two years.

- Annual quantities of each chemical treated on-site or off-site and the percent change from the previous year.

- Annual quantities of each chemical released to the environment due to catastrophic events, remediation of wastes on site, or any other event not associated with routine operations.

- Source reduction practices used for each chemical at the facility and the techniques used to identify additional opportunities for source reduction.

- The ratio of overall facility production to that of the previous year.

3.5.2 The Toxics Release Inventory

The Toxics Release Inventory (TRI) is an annual report required by Section 313 of the 1986 Emergency Planning and Community Right-To-Know Act (EPCRA), otherwise known as Title III of SARA. These regulations require that all manufacturing and production facilities employing more than 10 people full time must provide annual emissions estimates for over 300 chemicals and 20 chemical categories used for any purpose in amounts exceeding certain threshold limits. Emissions estimates for routine and accidental releases must be provided for each chemical and chemical group on separate forms (Form R) with estimates for release to the air, water, and land. These laws are based on the premise that the community and citizens near these facilities have a right to know about the use, storage, and emissions of toxic chemicals. This act has three main purposes:

- To inform the public and the government about possible chemical hazards to their community,

- To provide for planning in the case of chemical accidents, and

- To provide the public with a compiled and categorized annual inventory of releases and transfers of toxic chemicals - The Toxic Release Inventory.

For the reporting years 1987 through 1990, the TRI forms included an optional section for companies to report activities that reduced the generation of toxic chemical wastes. This section was expanded and made mandatory by the Pollution Prevention Act of 1990.

3.5.3 Uses For TRI Data

It is expected that this publicly available information will be reviewed closely by a number of special interest groups that are involved in public hearings and permitting activities for chemical producers and manufacturers.

The federal government has already used TRI data to form new environmental legislation such as the Clean Air Act Amendments of 1990. The EPA has also used TRI data for the implementation of existing programs involving permitting, inspection, enforcement targeting, compliance reviews, risk screening, and pollution prevention monitoring.

State governments are using TRI data in their permitting and pollution prevention programs. These uses involve:

- Development of permit requirements for facility discharges to air and water (NPDES and POTW permits).
- Determination of whether additional chemicals should be included in permit applications.
- Determination of whether additional control measures should be required.
- Targeting facilities with the greatest potential for waste reduction.
- Identification of facilities in need of state technical assistance in their waste reduction programs.

Users use of TRI data include public interest groups, citizen groups and universities. These groups analyze and report data for geographic areas, industries, or selected release media. One of the beneficial side-effects of good waste reduction performance is an improved public image for the facility or plant involved. This usually leads to an improved public perception and potential acceptance of their products as being produced in a environmentally responsible manner.

3.6 New Economic Justification For Waste Reduction

Economic considerations used to justify implementation of projects or systems that reduce hazardous waste and solid waste generation should include more than those traditionally used for plant process modifications or new installations. This is because waste reduction systems will have an ever increasing affect on the entire plant or facility in terms of:

- The type of waste generated,
- The amount of waste generated,
- Where in the plant it was generated, and
- The effects the waste will have on downstream operations.

These "whole plant" economic considerations should include the following at a minimum:

- The predicted future costs for handling, treating, transporting, and disposal of wastes generated,
- Positive effects on other unit operations within the plant such as reducing wastewater treatment and emissions control requirements,
- Increases in production yields that may result from installation of reclamation and reuse systems,

- The effects on company-wide waste reduction goals if planned waste reduction goals are not achieved at each plant,

- The effects of reducing the amount of process wastewater requiring treatment because of water reuse within the plant,

- The avoided costs of complying with new and restrictive wastewater treatment and pre-treatment standards,

- The avoided future costs of hazardous waste cleanup and long-term liability for feed water treatment sludges and other solid wastes that may become reclassified as hazardous wastes,

- The reduction in the long-term liability associated with hazardous waste generation and disposal,

- The reduced need for installation of future air emission control systems (i.e. MACT systems),

- Reduced CAAA emission fees and state taxes,

- Reduced costs associated with future monitoring and permitting of air emissions such as risk assessment and toxicology studies,

- Reduced costs associated with reducing VOC emissions from wastewater treatment systems.

Section 4: METHODOLOGY

4.1 Introduction

This section discusses a generic systematic methodology for conducting pollution prevention studies and how this methodology was applied to the pollution prevention study for crude oil units.

4.2 Generic Methodology for Pollution Prevention Studies

4.2.1 Logic Flow Chart

A logic flow diagram which describes a generic methodology for conducting pollution prevention studies is included as Figure 4.1.

4.2.2 Project Execution Strategy

A pollution prevention project begins in the same way that a process study would begin. The goals, objectives, scope, deliverables, and key issues of the study are captured in a project execution strategy.

A pollution prevention study must have a reference point, or base case. The project execution strategy will define the conventional process unit, or base case, against which the proposed pollution prevention measures will be evaluated. Once the base case is selected, the relevant process data, environmental data, and equipment specifications will be collected for subsequent comparative analyses in the pollution prevention study.

4.2.3 Idea Generation and Selection - The Creative Process

Brainstorming is a team problem-solving technique which is particularly effective in generating ideas for pollution prevention studies. A team of process and environmental specialists are invited to participate. The brainstorming session provides a creative and uninhibited atmosphere where ideas can be proposed without dwelling on details. Details are left to be fleshed out in the subsequent steps of the study. A literature search can be performed ahead of the brainstorming session to kick off the flow of ideas.

Following the creative storm of ideas, the candidate ideas are sorted by engineering system and the environmental medium being impacted. Some ideas may fit more than one category. The categories of engineering systems in order of priority are:

- Source Reduction: Process Modifications
- Source Reduction: Process Optimization
- Source Treatment
- Waste Segregation
- End-of-Pipe Treatment
- Fugitive Emission Management
- Containment
- Other

The categories of environmental media are:

- Air
- Wastewater
- Solid Waste
- Hazardous Waste

The ideas are then qualitatively rated for their anticipated environmental benefits and cost impacts using three simple grades:

- High
- Medium
- Low

It is now possible to identify those ideas which have the potential to yield the greatest return on investment; i.e., a high environmental benefit at relatively low cost. These ideas receive priority. A second list of medium benefit-to-cost ideas can also be prepared. All ideas are captured for future consideration and evaluation.

4.2.4 Evaluation of Ideas

The next step is to analyze how the pollution prevention ideas can be applied to a model new process unit (Case 1) and to a revamp of a conventional process unit (Case 2). Since the model new process unit begins as a blank sheet of paper, any idea can be considered. The revamp unit must necessarily consider technical and physical constraints. Not every good idea can be practically retrofitted to an existing unit.

Process Flow Diagrams (PFDs) are then developed to incorporate the pollution prevention ideas selected for Case 1 and Case 2. The resulting process operations are confirmed by computer simulations. Heat and material balances are prepared. Heat integration (pinch analysis) is performed to optimize the process. At the same time the process design is proceeding, the air emissions, wastewater loads, and solid and hazardous wastes can be quantified.

A list of equipment can be generated from the PFDs. Process engineers will size the equipment, set design conditions, and specify performance requirements. The cost estimate can now be prepared. Cost estimating specialists will price the new equipment for Case 1 and estimate the cost of modifying the existing equipment for Case 2. The target accuracy of the cost estimate is ± 35%.

A cost/benefit analysis is then developed from the results of the cost estimate and the anticipated process/environmental benefits. If a particular pollution prevention idea results in energy conservation or marketable product, the payback period can be calculated. If a particular idea results in reduction of a waste without a compensating recovery credit, the cost/benefit of the idea can be calculated in terms of cost per ton of pollutant controlled.

The final step in this methodology is to assemble the findings of the pollution prevention study into a report. The final report compares the model new process unit and the revamp conventional process unit to the base case. The final report concludes the study but does not represent the end of the pollution prevention process. Pollution prevention is not a static once-through process; it is a dynamic iterative cycle of regularly reevaluating systems to reduce pollution.

4.3 Pollution Prevention Methodology Applied to Crude Units

4.3.1 Project Execution Strategy

After award of this contract, API and Kellogg jointly prepared a project execution strategy. The project execution strategy established the project goals and objectives, scope of work, deliverables, budget, schedule, and work processes. The project execution strategy also defined the conventional crude unit, or base case. Refer to Section 2 of this report for further discussion.

4.3.2 Idea Generation and Selection

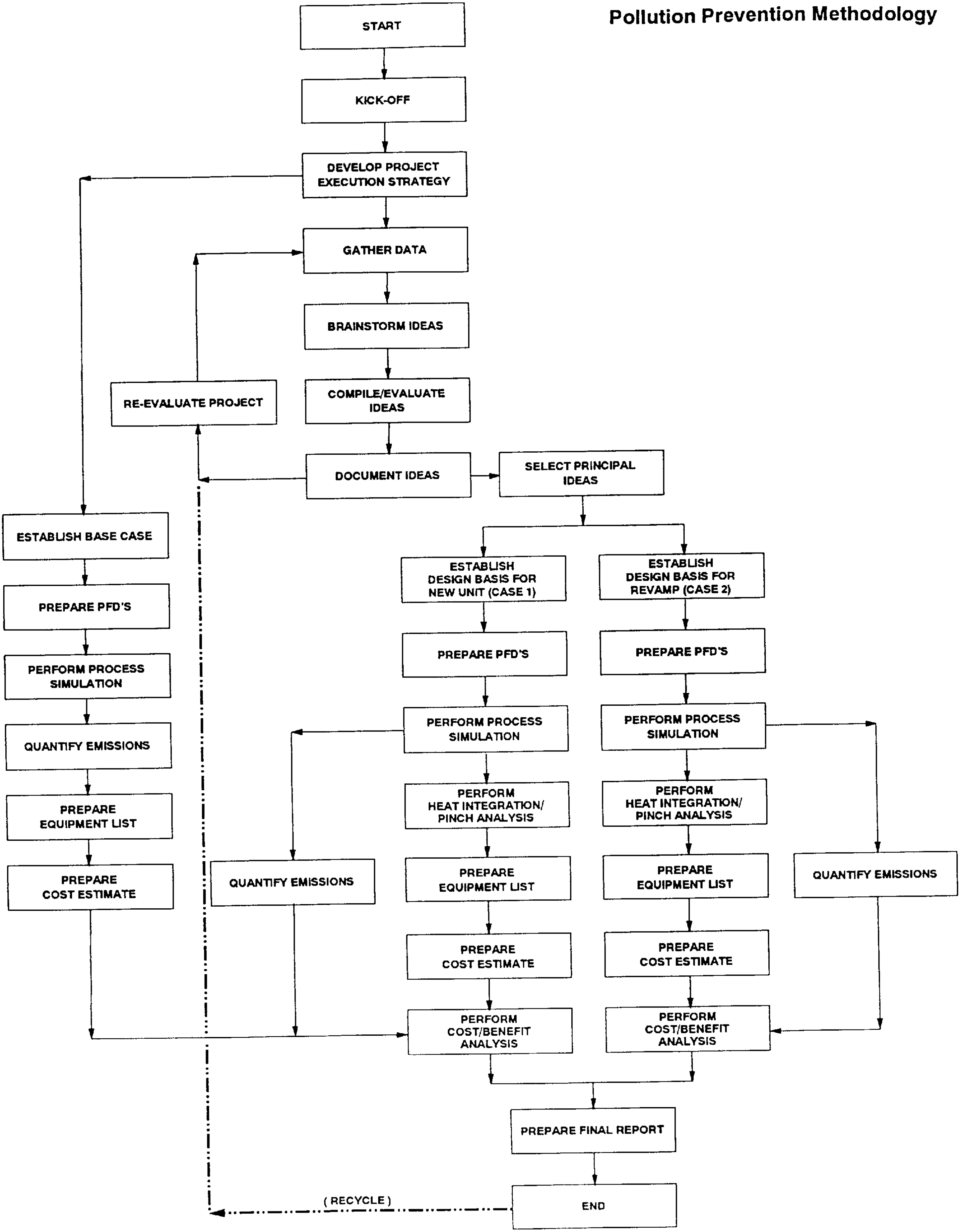
A literature search was performed and input from API committee members was solicited. Several brainstorming sessions were conducted with senior process refinery engineers, environmental engineers, and technical managers. The brainstorming sessions produced 116 pollution prevention ideas with potential application to crude units. The candidate ideas are presented in Appendix A, classified according to engineering system and environmental medium, and qualitatively rated for environmental benefits and cost impacts. Of the 116 ideas, a short list of 39 ideas were selected for further study based on qualitative cost/benefit analyses. These ideas are denoted with an asterisk in the listing in Appendix A.

4.3.3 Evaluation of Ideas

The ideas selected were examined for feasibility of application to Case 1 and Case 2. Ideas were struck if they were not commercially proven (i.e., if the idea was derived from an emerging technology or if it was not commercially available). A further constraint was imposed on Case 2: only ideas which could be implemented during a scheduled turnaround period were considered. In-house engineering expertise was used to evaluate ideas which fit these criteria.

Three sets of PFDs were developed: Base Case, Case 1, and Case 2 (refer to Appendices B, C, and D). The PFDs provided the basis for the material balance, computer simulation (Appendix H), pinch analysis (Appendix I), inventory of emissions and effluents (Sections 5.5, 6.5, and 7.5), equipment lists (Appendices E, F, and G), cost estimates (Sections 5.6, 6.6, and 7.6) and cost/benefit analyses (Sections 6.8 and 7.8).

Figure 4.1
Pollution Prevention Methodology



Section 5: CONVENTIONAL CRUDE UNIT (BASE CASE)

5.1 Introduction

The refinery unit selected for this study is a typical U.S. Gulf Coast crude and vacuum unit that was designed in the early 1980's, with a 175,000 BPSD capacity.

5.2 Design Basis

A representative crude, Light Arabian Crude of 34.50 API gravity, was selected as the single feedstock for process evaluation of all cases. Establishing an identical feedstock for the three cases allows for a unified analysis of the results.

The following items establish the process boundaries of the crude unit for this study:

- Utilities were assumed to be available from the refinery in adequate supply for maintaining reliable operation of the crude unit. Utilities include: electric power, fuel gas, cooling water, steam, instrument air, and plant air.
- Crude feed was assumed to be pumped from tankage at battery limits. Products were assumed to be sent to tankage or to adjacent units for further processing. In the latter case, product cool-down between units was not considered.
- Tanks for feed and intermediate products were not included in this study.
- Atmospheric crude tower overhead non-condensables were assumed to be compressed, cooled and sent to battery limits. Overhead liquid product was assumed to be sent to battery limits as unstabilized gasoline.
- Vacuum tower overhead jet system was included in this study. Non-condensable overhead vapor was assumed to be compressed and sent to amine treating for H_2S removal.

The crude unit will produce the slate of products shown in Table 5.1.

Steam side-stripping is employed to adjust front end boiling range for each side product. Stripped products have the following degree of fractionation:

Stripped Product	Fractionation
Overhead/Naphtha	+150 °F Gap
Naphtha/Kerosene	+ 60 °F Gap
Kerosene/HDF	+ 30 °F Gap
HDF/AGO	-500 °F Overlap

The product slate chosen is typical for this crude. Additional product stream characteristics are provided in Appendix H.

5.3 Process Description

The process flow diagrams for the Base Case are included in Appendix B (Dwg. Nos. P-7001-D, P-7002-D, and P-7003-D).

5.3.1 Crude Preheat Train

Crude charge is pumped from storage into the suction of the crude charge Pump, J-101. Stripped water from an offsite sour water stripper tower bottoms is mixed with the crude charge to provide an initial wash. This step minimizes the fouling of process lines and exchanger tubes due to salt or sludge deposition. The washed crude is then preheated in a series of process-to-process heat exchangers to an appropriate temperature for desalting.

The heated crude is fed to the two-stage desalter, where a dispersed mixture of water in the crude is formed, and water removal is effected by exposing the mixture to an electric field. Brine effluent from the second-stage desalter, F-102, is used to wash the incoming raw crude in the first-stage desalter F-101. The brine effluent from F-101 is cooled down by heat exchange with the fresh water, as well as cooling water, prior to discharging to the refinery Wastewater

Treatment Plant (WWTP). Desalted crude, which contains less than one pound of salt per thousand barrels, is pumped by the Desalted Crude Charge Pump, J-102, to a second series of process-to-process exchangers. The desalted crude temperature is elevated to 440 °F at the inlet of the atmospheric crude heater.

5.3.2 Crude Distillation

After preheating, the crude is fed to the Atmospheric Tower Feed Heater B-101, where it is heated to the desired temperature for feeding to Tower E-101. This heater is provided with air preheat and low NO_x burners. The design basis calls for taking the 670 °F TBP cut point material as atmospheric residue. The resulting flash zone temperature requirements for light Arabian crude is 668 °F, with a design overflash of 4 vol% on crude.

The atmospheric tower contains forty valve trays. Two pumparounds remove heat from the tower at the Heavy Distillate Fuel and Naphtha Product draws. At these pumparound locations, liquid is withdrawn from the tower, pumped through heat exchangers, and then returned to the tower two trays above the draw tray. Side-products are withdrawn from the crude tower, steam-stripped in sidestrippers, and then pumped to battery limits after heat exchange.

Atmospheric tower overhead is first cooled against the crude charge for optimum heat recovery then further cooled and condensed with cooling water in C-102. The partially condensed overhead vapors enter the overhead accumulator drum F-103, where uncondensed vapor, hydrocarbon liquid and free water are separated. Vapors are directed to the steam-driven atmospheric overhead compressor, X-101, where they are compressed and directed to the fuel gas system outside of battery limits. The hydrocarbon liquid is split into a reflux stream, which is directed to the tower, and a distillate product, which is sent to battery limits as unstabilized gasoline. Sour water is taken from a boot and sent to battery limits for treatment.

The atmospheric tower bottoms stream is pumped through the Vacuum Heater, B-102, to the Vacuum Tower. The vacuum heater is also equipped with an air preheat system and low NO_x burners.

5.3.2 Vacuum Distillation

The Vacuum Tower, E-108, is a packed column, operating at 35 mmHgabs in the flash zone, with no stripping steam. In order to obtain a 1025 °F + TBP cut point for the vacuum residue, a flash zone temperature of 750 °F is required. The tower is packed with a combination of stainless steel grid and rings. There is a product and pumparound draw for HVGO and LVGO. HVGO is pumped through a spray header over the grid in the wash oil zone. Wash oil from this section is withdrawn from a chimney draw tray and recycled through the vacuum heater by the Vacuum Tower Recycle Pump, J-122. A mesh pad is located above the wash oil section to eliminate entrainment to the HVGO section.

HVGO side-draw is withdrawn from a total-draw, chimney tray on level control. This stream is cooled against the crude charge and split into two streams: one is directed back to the tower as pumparound, and the other is further cooled before sending to storage as HVGO product.

LVGO side-draw is also withdrawn from a total-draw, chimney tray. After cooling, a pumparound stream is returned to the tower through the spray header above the packed bed. LVGO product is sent to storage outside battery limits.

Vacuum is created by a three-stage, steam jet ejector system. The ejectors, along with their surface condensers, are located on an elevated platform to provide a barometric leg into the Vacuum Tower Overhead Drum, F-108. Motive steam for the jets is nominal 150 psig steam. The overhead drum is maintained at 2 psig.

Sour water is separated from condensed hydrocarbon liquid and pumped to battery limits by Vacuum Condensate Pump, J-118. Recovered oil is skimmed by internal baffles and pumped by J-119 to recovered oil storage. These streams are sometimes sent to the crude desalters. Non-condensable vapors from the overhead drum flow to Vacuum Seal Drum, F-109, then to the Vacuum Off Gas Compressor X-102. The vapors are compressed and sent to the battery limits after passing through Vacuum Tower Off-Gas Knockout Drum, F-111. Any water condensate removed in this drum is drained to an oily water sewer.

5.3.4 Pollution Sources

5.3.4.1 Air Emissions

The two fired heaters, B-101 and B-102, represent the major sources of air emissions in the crude unit. Pollutant emission rates depend to a great extent on the type of fuel consumed. For this study, it was assumed that the two heaters are provided with both fuel oil and fuel gas burners. To examine the effect of fuel selection upon the pollutant emission rates, the following two fuel cases were considered:

- Fuel Gas Case: One hundred percent (100%) fuel gas (equivalent to pipeline grade natural gas) firing in all heaters. The fuel gas was assumed to contain 0.25 grains H_2S/100 scf.

- Fuel Oil Case: Fuel oil firing in the Atmospheric Crude Heater (B-101), and fuel gas firing in all other heaters. Fuel oils with different levels of sulfur were considered: 0.2, 1.0, and 3.34 wt% sulfur.

High-sulfur fuel is produced as the vacuum tower bottoms stream. Low-sulfur fuel oils were included to reflect their commercial availability.

Furnace selection was based on a minimum heater efficiency of 93%. All furnaces in the Base Case were assumed to be equipped with first generation low NO_x burners generating 0.1 lb-NO_x/MMBTU for fuel gas firing and 0.2 lb-NO_x/MMBTU for fuel oil firing.

5.3.4.2 Liquid Effluents

Aqueous effluents from the crude unit include condensed stripping steam, condensed motive steam from the jet ejectors, and the desalter effluent.

5.3.5 Waste Minimization Practices

The Base Case crude unit utilizes low-NO_x burners in fired heaters and offsite boilers. Two stage desalting is employed for salt removal from the raw crude. Sour water, collected from both the crude and vacuum overhead accumulators, is sent to an offsite sour water stripper for H_2S and NH_3 removal and then returned to the desalters as wash water.

5.4 Chemical and Utility Requirements

The chemical and utility requirements for the Crude Unit are presented in Table 5.2 entitled "Chemical Requirements'" and Table 5.3 entitled "Utility Requirements."

5.5 Inventory of Emissions and Effluents

5.5.1 Point Source Emissions and Effluents Inventory

Piping & Instrumentation Diagrams (P&ID's) were used to compile a list of all point source emissions. This inventory is shown in Table 5.4, which classifies the sources into four categories:

- Valves and Fugitive Emissions
- Oily Water Sewer
- Storm Sewer
- Instruments

Major point sources producing air emissions and liquid effluents were counted. The cooling tower was not included in this inventory.

Drains to the Oily Water Sewer were classified by type and included in the inventory. Drains to the Storm Water sewer (process condensate drains) were also classified and counted. Instrument drains, including control valves, level bridles, and other devices with drains were included.

5.5.2 Air Emissions

Air emissions can be divided into stack emissions and reportable non-stack (fugitive) emissions. Sources falling under the stack emissions category include the two heaters and the offsite boiler. Fugitive emissions are comprised of VOC leaks from piping components.

Since all air emission sources in a refinery have an impact on the air permit, it is not possible to completely subdivide the refinery into stand-alone units with arbitrarily established boundaries. The offsite boiler actually lies outside the boundaries defined in section 2.6, but the air emissions resulting from generating steam used in the crude unit should be attributed to the crude unit.

5.5.2.1 Stack Air Emissions

As discussed in section 5.3.4.1, four different fuel firing cases were considered. Summaries of all stack air emission sources associated with the Crude Unit are shown in Table 5.5, 5.6, 5.7, and 5.8, one table for each fuel case. The point sources of air emissions include process heaters and offsite boilers (emissions caused by energy and steam usage in the crude unit).

Emission rates of volatile organic compounds (VOC), carbon monoxide (CO), and total suspended particulates (TSP) from the stacks were calculated using air emission factors from the EPA's universal reference "Compilation of Air Pollutant Emission Factors," Publication AP-42, Fourth Edition, September 1985 (hereinafter AP-42). Exceptions to this are outlined below.

The fuel gas was assumed to have a heat value of 900 BTU/scf, and a sulfur content of 2500 gr/MMscf. Since the sulfur content is greater than the AP-42 upper limit of 2000 gr/MMscf, sulfur dioxide (SO_x) emission rates from the fired heaters and boilers were calculated by assuming that all sulfur is converted to SO_x.

Fuel oil calculations for TSP and SO_x were based on AP-42 formulas. The AP-42 emission factor for TSP is based on the formula (10S + 3) lb-TSP/10^3 gal, where S is the weight percent of sulfur in the fuel oil. The AP-42 emission factor for SO_x is based on 157S lb-SO_x/10^3 gal, where S is also the weight percent of sulfur in the fuel oil. The fuel oil was assumed to have a heating value of 136,000 BTU/gal.

The Base Case assumes the use of low NO_x burners in process heaters and offsite boilers. For these combustion sources, emission factors for low NO_x burners of 0.2 lb-NO_x/MMBTU for fuel oil and 0.1 lb-NO_x/MMBTU for fuel gas were taken to represent typical performance of first-generation low NO_x burners. The process heaters are equipped with air preheat systems. Boiler efficiency was assumed to be 80%.

Process vents and relief valves in the crude unit will be routed to the refinery flare. The only non-emergency flare loads attributable to the crude unit will be (1) small amounts of purge gas used to sweep the crude unit flare header, and (2) small amounts of process gases which leak past the relief valve disks. Emissions from flaring these loads will be trivial and, therefore, have not been included in the air emission inventory.

5.5.2.2 Fugitive Emissions

Fugitive emissions include leaks from valves, drain emissions from sewers, leaks into the cooling water system, emissions from sampling operations, and leaks from pump seals, compressor seals, relief valves, flanges, etc. Fugitive emissions were estimated per AP-42, which provides emission factors and methods for calculations. Fugitive emission calculations are summarized in Table 5.9a. Fugitive VOC emissions from the cooling tower were not included.

The Base Case refinery was assumed not to have a formal inspection & maintenance (I&M) program for controlling fugitive VOC emissions. Only two fugitive control measures were assumed to have been implemented:

- Routing of relief valves and process vents to flare, and
- Capping of open-ended valves.

In the AP-42 methodology, the calculation of fugitive VOC emissions is a function of fluid service, leak concentration, equipment count, and equipment condition. Equipment condition is determined by equipment design and I&M (leak definition, inspection frequency, and repair response time). Fugitive VOC emissions are independent of equipment size, fluid throughput, fluid temperature, and fluid pressure in the AP-42 methodology.

5.5.2.3 SARA Constituents in Fugitive Emissions

Fugitive releases of SARA constituents are assumed to be at the same concentration in the leak as in the contained fluid. Table 5.9b shows the concentration ranges of five SARA compounds in crude oil and crude unit product streams. The ranges reported are derived from limited data and represent reasonable estimates of the concentrations in the total fugitive VOC emissions calculated for typical crude oil distillation units. Concentrations of the same five SARA compounds in a sample assay of Arabian Light Crude Oil are shown for comparison. The composition of any crude oil feedstock is known to change over time due to variations in the oil field, so this assay should not be considered representative of all Arabian Lights. The last column in Table 5.9b gives the estimated ranges of SARA compound releases based on the given concentrations.

The range of concentrations in Table 5.9b is broad enough to include paraffinic crudes and most aromatic crudes. The specific SARA compounds listed tend to be concentrated in the light distillate product streams of the crude tower, such as straight run naphtha, because of their respective boiling points. The distribution of these compounds in light liquid service and in vapor service are affected not only by their original concentration in the raw crude, but also by the yield of each product stream (or "cut"), the separation efficiency of the crude tower trays, and the presence of auxiliary equipment, such as preflash drums and pumparounds. Therefore, the concentrations listed represent reasonable lows and highs (not necessarily minima and maxima) within the expected spectrum of experience for crude distillation towers.

5.5.2.4 Benzene NESHAP

Central to determining benzene NESHAP compliance status for a refinery is the Total Annual Benzene quantity (TAB) determination. TAB from facility waste is the sum of the annual benzene quantity for each waste stream at the facility that has a flow-weighted annual average water content greater than 10 percent. NESHAP Subpart FF describes a procedure for determining TAB (refer to 40 CFR 61.355). For a crude unit, there are abundant references from the many benzene calculations already performed.

A benzene NESHAP emissions estimate has been prepared for the Base Case crude unit and is shown in Table 5.10. The annual benzene quantity is estimated at 27.7 metric tons per year for the crude unit alone. In developing this estimate, it was assumed that the desalter effluent contains 20 ppmw benzene and the crude contains 5000 ppmw benzene.

One of the largest single sources of benzene in the NESHAP inventory is the desalter effluent. Vessel drainage is another significant contributor. For purposes of this study, process vessels were assumed to be drained to the process sewer. The annual flows from the vessels were averaged assuming each vessel would not be drained more than once a year.

5.5.3 Stormwater and Wastewater

5.5.3.1 Stormwater

The Base Case refinery has segregated stormwater and oily water sewer systems. There are 43 condensate steam drains to the storm sewers shown on the Base Case P&ID's. Condensate can contain many undesirable pollutants including oil and chemicals used for corrosion control. Condensate to the storm sewer could cause the refinery to violate the terms of its stormwater permit; that is, condensate may cause the stormwater effluent to fail the biotoxicity test or other tests.

The cooling water blowdown is discharged to the refinery WWTP. The cooling tower blowdown salts can precipitate in the sewer system, particularly after contacting caustic wastes which cause an alkalinity shift. For the purposes of this study, it was assumed that 50% of the salts in the cooling tower blowdown and the various other blowdowns precipitate in the sewer system or the API Separator and are settled out as sludge in the API Separator.

5.5.3.2 Wastewater (Oily Water or Process Wastewater)

An inventory of sources of oily water or process wastewater was estimated and summarized in Table 5.11. An actual inventory would require an on-site inspection, and such inspection could reveal other point sources than those shown in Table 5.11.

The flow rate and oil & grease (O&G) values for the desalter were extracted from the design information. The other parameters for the desalter were selected to be representative of crude units. Based on earlier studies, it was estimated that the Base Case refinery would produce approximately 7,200 lb/day of sludge in the API separator. Some solids in the API sludge originate as Bottoms, Sediment, and Water (BS&W) in the oil. Other sources include filters, equipment rust, and various reactions among different types of wastewaters. Data on the flow rates and O&G content for the sample drains, instrument drains, and vessel drains were extracted from the NESHAP TAB estimate.

The boiler blowdown and steam condensate loss were estimated at 2% of the total steam usage. The cooling tower blowdown rate was estimated by assuming that the cooling tower operates at 5 cycles of concentration, and that windage loss is 0.3% of circulation. Water plant sludge generation was estimated at 5% of water production. Boiler water treatment plant discharge rate to the process sewer was estimated at 12% of boiler water production.

Flow to the refinery WWTP from the crude unit was estimated at 584 gpm. Approximately 228 gpm of stripped sour water is reused in the desalter; thus, sour water is shown as both a credit and debit on the inventory in Table 5.11. All the stripped sour water is reused in the desalter. The desalter is a major contributor of process wastewater within the crude unit, and the wastewater is contaminated with solids, phenols, COD, NH_3, and Sulfides.

VOC emissions from sewer systems are regulated under NSPS Subpart QQQ, which affects units constructed or modified after May 4, 1987. Since the Base Case refinery was constructed prior to the effective date of Subpart QQQ, it was assumed that the existing equipment and sewers do not meet these standards.

5.5.4 Solid and Hazardous Wastes

The Base Case assumes that four listed RCRA hazardous wastes can be associated with the crude unit: Dissolved Air Flotation (DAF) float (K048), slop oil and API skimmed oil emulsion solids (K049), heat exchanger bundle cleaning sludge (K050), and API separator sludge (K051). These

K-wastes are listed hazardous wastes from specific sources as defined in 40 CFR 261.32. Quantities of these wastes, except for K050, are shown in Table 5.12.

In the Base Case, all quantified solid wastes were assumed to be discharged into the process sewer and contributed to the generation of API separator sludge or DAF unit float in the refinery WWTP. It is assumed for the purpose of this study there are no hazardous wastes from non-specific sources, such as F037 and F038 wastes. Even if there were F wastes from non-specific sources, the total of F and K wastes would not be different from the total quantity represented in Table 5.12. Maintenance operations frequently produce K050 wastes, but these are also not considered in this study.

API recently published the results of the 1989 solid waste survey of 117 refineries in Publication No. 849-30300, "Generation and Management of Wastes and Secondary Materials 1989: Petroleum Refining Industry Performance." Comparing the aggregate figures on solid waste generation to crude throughput, the 1989 survey results indicate that the quantity of solid waste generated by the refining industry as a whole represents approximately 0.08 weight % of the crude feed rate. Applying this industry-wide waste/throughput ratio, the Base Case 175,000 BPSD refinery would produce about 209 tons/day of solid wastes, a portion of which is derived from the crude unit. The solid waste inventory in Table 5.12 shows an estimated total of 6.3 tons/day (12,535 pounds/day) of solid wastes from the crude unit, which would constitute approximately 3% of the total refinery solid wastes.

5.6 Cost Estimate

The basis for the cost estimate is a 175,000 BPSD crude/75,000 BPSD vacuum unit constructed today, but designed to 1980 industry standards. The accuracy of the cost estimate is +/- 35%. Qualifications and exclusions are summarized below:

5.6.1 Estimate Qualifications

- 1st quarter 1992 investment cost for U.S. Gulf Coast region.

- Cost estimate is not a bid price.

- Assumptions:
  - battery limit unit
  - site is clear and level with reasonable site access
  - adequate utilities are provided at battery limits
  - material sourcing is worldwide
  - 40 hour construction work week

5.6.2 Estimate Exclusions

- offsite facilities.
- site survey, soils investigation, and site preparation.
- capital, commissioning, operating and maintenance spares, startup and commissioning costs.
- catalyst and process chemicals.
- forward escalation.
- sales and use taxes, local taxes, fees, and permits.
- license fees and royalties.
- general and administrative overhead.
- land cost.

5.6.3 Cost Methodology

This cost estimate was factored from equipment cost and equipment counts (refer to Appendix E for equipment list) using M.W. Kellogg's capital cost estimating system (CAPCOST). The cost estimate methodology is outlined below.

5.6.3.1 Equipment

Equipment capacity and sizes were determined by Process Engineering. The equipment sizing parameters were run through an in-house equipment sizing program. Specialty and large dollar items were verified by M.W. Kellogg in-house database and vendor quotes.

5.6.3.2 Bulks

Bulks refer to commoditites which are not engineered equipment items. Examples of bulks include concrete, steel, and wire. Bulks were factored from equipment using the CAPCOST program. Adjustments were made on the bulk ratios based on in-house cost data from a crude and vacuum unit which bears the same nameplate capacity as the Base Case.

5.6.3.3 Subcontracts

Paint, insulation, and fireproofing were included as specialty subcontracts that were factored from equipment, piping and structural steel. The balance of specialty subcontracts such as pilings, buildings, and field erected towers were factored using the CAPCOST program.

5.6.3.4 Construction

Construction rates were developed by M.W. Kellogg Estimating Services. The basic manhours were calculated using the CAPCOST program. U.S. Gulf Coast construction factors and rates were used.

5.6.3.5 Home Office Services

Home office manhours including construction home office were estimated by the CAPCOST program.

5.6.4 Base Case Cost

The cost estimate for the Base Case totals $128,688,000. This estimate is the total installed cost for building the base case crude unit in the U.S. Gulf Coast region. Qualifications for the estimate are given in section 5.6.1 and exclusions are noted in section 5.6.2 of this report.

5.7 Summary and Conclusions

The major category of emissions for this hypothetical case (in terms of mass and volume) is the stack emissions. Wastewater is the second largest category. Other emissions are RCRA wastes, benzene NESHAP wastes, and fugitive air emissions.

The total fossil fuel energy use for the Base Case is 948 MMBTU/hr, and the electricity usage is 2,670 KW. Substitution of electrical energy for fossil fuel energy would reduce emissions. However, this reduction of emissions at the crude unit is accompanied by an increase in emissions at the power plant. Power plant emissions are not charged against the refinery's emissions inventory unless the power plant is located on site and under the control of the refinery.

The air emissions are summarized in Table 5.13. SO_x and TSP emissions increase proportionally with increasing sulfur content of the fuel. NO_x emissions from burning fuel oil are approximately twice as high as NO_x emissions from burning fuel gas.

Table 5.13 includes 176 tons/year of fugitive VOC emissions from piping components.

The annual benzene quantity for the crude unit is 27.7 metric tons/year. This is above the 10 metric ton/yr threshold in NESHAP Subpart FF for the crude unit alone. Therefore, the Base Case refinery would be required to implement control measures to reduce its TAB.

Total wastewater flow produced by the crude unit is 584 gpm. The wastewater contains 233 gals/day of O&G, 10,710 lbs/day of TSS, 1,193 lbs/day of BOD, 4,571 lbs/day of COD, 572 lbs/day of NH_3, 159 lbs/day of sulfides, and 199 lbs/day of phenols.

A total of 6.3 tons per day of solid wastes are produced. Because non-hazardous and hazardous constituents of this waste are mixed together, all of this solid waste quantity is RCRA hazardous waste.

By inspection of the above figures for the Base Case, the fired heaters, boilers, stripping steam users, and fugitive emissions will play an important role in the area of waste reduction.

TABLE 5.1

SLATE OF PRODUCTS FOR ALL CASES

Product	Nominal TBP Cut Point Temperatures
Crude Tower Overhead	300°F and lighter
Naphtha	300-375°F
Kerosene	375-475°F
Heavy Distillate Fuel (HDF)	475-620°F
Atmospheric Gas Oil (AGO)	620-670°F
Light Vacuum Gas Oil (LVGO)	670-740°F
Heavy Vacuum Gas Oil (HVGO)	740-1025°F
Vacuum Residue	1025+°F

TABLE 5.2

BASE CASE - CHEMICAL REQUIREMENTS

User Chemical	Chemical Requirements	
Desalter		
Emulsion Breakers	0.75	GPH
Caustic	0-0.5	GPH 31°Be
Crude Tower		
Ammonia (anhydrous)	8	LBS/HR
Corrosion inhibitors	0.7	GPH
Cooling Tower		
Chlorine	50	LBS/HR
Zinc-Chromate	0.04	GPH
Dispersant	0.09	GPH
Biocide	0.5	LBS/HR
Sulfuric Acid	5	LBS/HR

TABLE 5.3

BASE CASE

UTILITY REQUIREMENTS

Cooling Water Circulation	29,900 GPM	
Electricity Consumption	2,670 KW	
Fossil Fuel	948 MMBTU/hr	
Steam		
500# Consumption	120,010	LBS/HR
Production	120,010	LBS/HR (1)
125# Consumption	130,526	LBS/HR
Production	53,240	LBS/HR
50# Consumption	65,024	LBS/HR
Production	11,784	LBS/HR
15# Consumption	10,000	LBS/HR
Production	69,710	LBS/HR

(1) From steam boilers in OSBL utility area.

TABLE 5.4

BASE CASE
EMISSION POINT SOURCE INVENTORY

SOURCE	NUMBER OF SOURCES
Valves & Fugitive Emissions	
Valves	
gas service (Class II per AP-42)	272
light liquid (Class III per AP-42)	199
heavy liquid (Class IV per AP-42)	1331
Flanges (estimated)	3082
Relief Valves	37
Pump Seals	
light liquid	10
heavy liquid	32
Compressor Seals	3
Drains	126
Oil Water Sewer	
Sample Coolers	24
Relief Valves	31
Vessel Drains	60
Other Drains	127
Storm Sewer	
Condensate	43
Other Drains	0
Instrument Drains	
Control Valves	71
Level Bridles	20
Other Drains	1

TABLE 5.5

BASE CASE
AIR EMISSIONS
(FUEL GAS CASE)

EMISSION SOURCE	DESCRIPTION	HEAT RELEASE (MMBTU/HR)	AIR EMISSIONS (Tons/Year) NO_x	CO	VOC	TSP	SO_2
FUEL GAS							
B-102	Vacuum Heater	149.5	65.48	29.10	1.02	3.64	0.52
OSBL	Boilers	382.5	167.54	74.46	2.61	9.31	1.33
B-101	Atmospheric Heater	416	182.21	80.98	2.83	10.12	1.45
	Total Energy	948					
	ANNUAL STACK EMISSIONS		415.22	185.54	6.46	23.07	3.30
	ANNUAL FUGITIVE EMISSIONS (from Table 5.9a)		0	0	176.11	0	0
	TOTAL ANNUAL AIR EMISSIONS		415.22	184.54	182.57	23.07	3.30

TABLE 5.6

BASE CASE
AIR EMISSIONS
(0.2% S FUEL OIL CASE)

EMISSION SOURCE	DESCRIPTION	HEAT RELEASE (MMBTU/HR)	AIR EMISSIONS (Tons/Year)				
			NO_x	CO	VOC	TSP	SO_2
FUEL GAS							
B-102	Vacuum Heater	149.5	65.48	29.10	1.02	3.64	0.52
OSBL	Boilers	382.5	167.54	74.46	2.61	9.31	1.33
FUEL OIL							
B-101	Atmospheric Heater	416	364.42	66.99	10.18	66.99	420.69
	Total Energy	948					
	ANNUAL STACK EMISSIONS		597.43	170.55	13.81	79.93	422.54
	ANNUAL FUGITIVE EMISSIONS (from Table 5.9a)		0	0	176.11	0	0
	TOTAL ANNUAL AIR EMISSIONS		597.43	170.55	189.92	79.93	422.54

TABLE 5.7

BASE CASE
AIR EMISSIONS
(1.0% S FUEL OIL CASE)

EMISSION SOURCE	DESCRIPTION	HEAT RELEASE (MMBTU/HR)	AIR EMISSIONS (Tons/Year)				
			NO_x	CO	VOC	TSP	SO_2
FUEL GAS							
B-102	Vacuum Heater	149.5	65.48	29.10	1.02	3.64	0.52
OSBL	Boilers	382.5	167.54	74.46	2.61	9.31	1.33
FUEL OIL							
B-101	Atmospheric Heater	416	364.42	66.99	10.18	174.17	2103.43
	Total Energy	948					
	ANNUAL STACK EMISSIONS		597.43	170.55	13.81	187.11	2105.28
	ANNUAL FUGITIVE EMISSIONS (from Table 5.9a)		0	0	176.11	0	0
	TOTAL ANNUAL AIR EMISSIONS		597.43	170.55	189.92	187.11	2105.28

TABLE 5.8

BASE CASE
AIR EMISSIONS
(3.34% S FUEL OIL CASE)

EMISSION SOURCE	DESCRIPTION	HEAT RELEASE (MMBTU/HR)	AIR EMISSIONS (Tons/Year)				
			NO_x	CO	VOC	TSP	SO_2
FUEL GAS							
B-102	Vacuum Heater	149.5	65.48	29.10	1.02	3.64	0.52
OSBL	Boilers	382.5	167.54	74.46	2.61	9.31	1.33
FUEL OIL							
B-101	Atmospheric Heater	416	364.42	66.99	10.18	487.67	7025.46
	Total Energy	948					
	ANNUAL STACK EMISSIONS		597.43	170.55	13.81	500.62	7027.31
	ANNUAL FUGITIVE EMISSIONS (from Table 5.9a)		0	0	176.11	0	0
	TOTAL ANNUAL AIR EMISSIONS		597.43	170.55	189.92	500.62	7027.31

TABLE 5.9.a

BASE CASE
FUGITIVE VOC EMISSIONS CALCULATIONS

SOURCE	STREAM COMPOSITION	NUMBER OF SOURCES	AP-42 EMISSION FACTOR (LB/HR/SOURCE)	CONTROL METHOD	CONTROL EFFICIENCY %	CONTROLLED EMISSION (LB/HR)	CONTROLLED EMISSION (TON/YR)
Valves	gas	272	0.059	none	0	16.048	70.290
	light liquid	199	0.024	none	0	4.776	20.919
	heavy liquid	1331	0.0005	none	0	0.666	2.915
Pump Seals	light liquid	10	0.25	none	0	2.500	10.950
	heavy liquid	32	0.046	none	0	1.472	6.447
Flanges	gas	347	0.00056	none	0	0.194	0.851
	light liquid	283	0.00056	none	0	0.158	0.694
	heavy liquid	2452	0.00056	none	0	1.373	6.014
Open-Ended Valves		489	0.005	capped	100	0.000	0.000
Relief Valves		37	0.36	to flare	100	0.000	0.000
Compressor Seals		3	1.4	none	0	4.200	18.396
Drains		126	0.07	none	0	8.920	38.632
Sample Connections		24	none	none	0	0.000	0.000
			TOTAL FUGITIVE EMISSIONS			40.207	176.108

TABLE 5.9.b

BASE CASE
SARA CONSTITUENTS IN FUGITIVE VOC EMISSIONS

SARA COMPOUND	LIGHT LIQUID SERVICE	VAPOR SERVICE	CRUDE OIL SERVICE	EXAMPLE ASSAY OF ARABIAN LIGHT	ESTIMATED LBS/YEAR
	WEIGHT PERCENT OF TOTAL				
Benzene	0.2 - 2.0 %	0.0 - 0.5 %	0.0 - 0.5 %	0.12 %	285 - 3743
Toluene	0.5 - 5.0 %	0.0 - 0.5 %	0.0 - 1.0 %	0.64 %	712 - 8015
Ethylbenzene	0.2 - 2.0 %	0.0 - 0.5 %	0.0 - 0.5 %	0.39 %	285 - 3743
Xylene	0.5 - 5.0 %	0.2 - 1.5 %	0.0 - 1.5 %	1.03 %	1070 - 9806
Cyclohexane	0.5 - 2.0 %	0.0 - 0.5 %	0.0 - 1.0 %	0.26 %	712 - 3743

TABLE 5.10

BASE CASE
BENZENE NESHAP EMISSIONS ESTIMATE

SOURCE	WATER OR ORGANIC	CONTROL METHOD	FLOW (GPM)	ESTIMATED BENZENE CONC. (PPMW)	ANNUAL EMISSIONS (MG/YR)
DESALTER EFFLUENT	Water	NONE	331	20	13.16
SAMPLING POINTS	Organic	NONE	0.011	5000	0.11
LEVEL BRIDLES	Organic	NONE	0.04	5000	0.39
	NUMBER	SHUTDOWNS PER YEAR	DRAIN (GPY)		
VESSEL DRAINS					
COLUMNS	2	0.25	377000	5000	7.13
EXCHANGERS	66	2	184800	5000	3.49
FIRED HEATERS	3	1	3600	5000	0.07
PUMPS	42	2	1680	5000	0.03
VESSELS	11	0.5	173800	5000	3.29
TOTAL ANNUAL BENZENE EMISSION ESTIMATE					27.68

TABLE 5.11

BASE CASE
WASTEWATER INVENTORY

		POLLUTANTS CONCENTRATIONS (PPMW)							MASS FLOW (LBS/DAY EXCEPT O&G IN GALS/DAY)						
SOURCE	FLOW GPM	OIL & GREASE	TSS	BOD	COD	NH$_3$	SULFIDES	PHENOL	OIL & GREASE	TSS	BOD	COD	NH$_3$	SULFIDES	PHENOL
DESALTER EFFLUENT	331	250	150	300	1150	144	40	50	119.16	596.28	1192.55	4571.45	572.43	159.01	198.76
SAMPLING DRAINS	0.01								15.85						
INSTRUMENTS	0.04								57.14						
VESSEL DRAINS	0.08								40.60						
BOILER BLOWDOWN (OSBL) & STEAM CONDENSATE	10	0	2500				0	0		150.12					
COOLING TOWER BLOWDOWN (OSBL)	133		600				0	0		479.18					
WATER PLANT SLUDGE (OSBL)	78	0	20000				0	0		9367.49					
BOILER EFFLUENT (OSBL)	32	0	600				0	0		117.02					
SOUR WATER TO SOUR WATWER STRIPPER	228														
STRIPPED SOUR WATER TO DESALTER	-228														
TOTALS	584.08								232.75	10710.09	1192.55	4571.45	572.43	159.01	198.76

TABLE 5.12

BASE CASE
SOLID AND HAZARDOUS WASTE INVENTORY

Waste	Quantity (tons/day)
Wastewater Treatment Sludges/Hazardous Wastes	
DAF Float and Slop Oil Emulsion Solids (K048 and K049)	0.9
API Separator Sludge (K051)	5.4
Non-Hazardous Wastes	
None (mixed with hazardous wastes)	0
Total	6.3

TABLE 5.13

BASE CASE
SUMMARY OF AIR EMISSIONS

(Tons/year)

FUEL	NO_x	CO	VOC	TSP	SO_x
Fuel Gas	415	185	183	23	3.3
Fuel Oil					
0.2% Sulfur	597	171	190	80	423
1.0% Sulfur	597	171	190	187	2105
3.34% Sulfur	597	171	190	501	7027

Section 6: MODEL NEW CRUDE UNIT (CASE 1)

6.1 Introduction

Case 1 represents the design of a new 175,000 BPSD crude unit incorporating a state-of-the-art environmental control philosophy.

6.2 Design Basis

The design crude type, feed rate, and product slate for this case are the same as for the Base Case outlined in Table 5.1. Product specifications are essentially the same for both cases.

The process design for this case was developed with an objective to reduce energy requirements and minimize production of wastewater (or sour water), while producing products of acceptable quality.

The list of ideas that were incorporated in the design of the model new crude unit is as follows:

- Apply pinch analysis (refer to Appendix I) to the crude preheat train. Increase crude preheat temperature and minimize heat losses to air and cooling water.
- Increase crude distillation column pumparounds from two to four. Reboil sidestrippers with a heat transfer oil rather than using steam stripping.
- Lower vacuum column flash zone pressure from 35 to 20 mmHgabs. This will lower furnace fired duty and reduce cracking of the feed to lighter products and secondary material.
- Use vacuum pump in place of the third stage steam jet ejector on the vacuum tower overhead.
- De-oil desalter brine and strip for benzene removal.

- Install state-of-the-art low NO_x burners. Use a Selective Catalytic Reduction (SCR) process for the reduction of NO_x in heater flue gas.

- Scrub flue gas for removal of SO_x when burning high sulfur fuel oil in heaters.

- Optimize water reuse by application of sidestream softening to blowdown streams.

- Apply advanced process control to optimize energy utilization. Install analyzers to provide continuous monitoring of emissions.

- Reduce fugitive emissions by the following methods:
    - Select leakless valves.
    - Use double seals on pumps.
    - Minimize flanges and install sealing rings on flanges.
    - Blind flanges on vent and drain valves.
    - Route relief valves to flare and/or seal with rupture disks.
    - Vent compressor distance pieces to flare.
    - Install a Maintenance Drain Out (MDO) system and eliminate all VOC from open drains.
    - Totally close loop all samplers.

Other ideas that were considered but not used are listed below:

- Eliminate crude tower sidestrippers completely.

- Eliminate stripping steam to the crude tower completely.

- Remove oil and grease and suspended solids from desalter effluents.

- Apply distributed distillation techniques to the atmospheric crude distillation column.

- Use membranes for cleaning up desalter brine.

- Consider an all-packed atmospheric crude tower instead of a trayed tower.

Refer to Appendix K for a report on these studies.

6.3 Process Description

The process flow diagrams for Case 1 are included in Appendix C (Dwg. Nos. P-7004-D, P-7005-D, and P-7006-D).

6.3.1 Crude Preheat Train

The process flowsheet for the crude preheat train of Case 1 is similar to that of the Base Case. The differences between the two cases are highlighted below:

> The crude is first heat-exchanged with atmospheric tower overhead vapor in exchanger C-101. The crude is then split into four parallel streams (branches). Each branch is heat-exchanged with a different process stream including the Naphtha pumparound, Heavy Distillate Product, HVGO, Kerosene Product, and Atmospheric Gas Oil Product. Downstream of the process-to-process exchangers, the crude is recombined into a single stream for feeding to the two-stage desalter. The mixed temperature is 298 °F at this point. After desalting, the crude is flashed to low pressure for the purpose of totally removing any remaining free water which is a major source of exchanger corrosion. Flashed crude then exchanges heat with the Heavy Distillate Product and is split into two branches with branch-to-total crude ratio of 80% and 20%, respectively. Additional process-to-process heat exchange is effected in several exchangers utilizing HVGO Product, Kerosene pumparound, Vacuum Residue, Kerosene Product, and HVGO pumparound to preheat the desalted crude.

C-128 and C-127 provide crude preheat from both HVGO Product and Pumparound. C-106 is the primary Heavy Distillate Pumparound to crude exchange. C-157 and C-131 represent primary Vacuum Residue to crude exchange. The crude is split 75%/25% upstream of C-127. The smaller stream exchanges with AGO Product in C-158, followed by exchange with AGO Pumparound in C-159. The combined crude temperature leaving C-131 to the crude tower furnace is 550 °F, approximately 110 °F higher than that calculated for the Base Case. This results in a lower heat duty for the Atmospheric Crude Heater, B-101, which translates to lower emission rates.

6.3.2 Crude Distillation

The Atmospheric Crude Tower operation in Case 1 is very similar to that described for the Base Case. The primary differences are at the product draw trays and side strippers for the Naphtha, Kerosene and HDF products. Product specifications are met by reboiling these strippers as opposed to the direct steam stripping employed in the Base Case. Steam stripping is still used for the AGO product because it is too hot to be reboiled without fouling. A pumparound is provided at each product draw (total of four pumparounds).

6.3.3 Vacuum Distillation

For this model new crude unit design, the Vacuum Tower operating pressure was reduced from 35 mmHgabs to 20 mmHgabs, and a dry vacuum system was used as in the Base Case. Lowering the operating pressure on the vacuum tower results in reducing the flash zone temperature. This translates to lower furnace tube wall film temperature, hence, a lower potential for cracking and/or coking of the furnace tubes. In the dry vacuum mode, no steam injection into the furnace passes will be required for the prevention or removal of coke deposits. Therefore, it becomes more important that high temperatures be avoided as much as possible.

With a flash zone pressure at 20 mmHgabs, the furnace outlet temperature will be maintained at 695 °F to obtain a 1025 °F TBP cut point on the Resid when processing Light Arabian Crude. Vacuum tower resid is pumped with J-123 and heat-exchanged with the crude in exchangers C-131, C-157, and C-156. The resid is then boosted by pump J-130 and used to generate steam in C-161, a kettle-type exchanger. This exchanger will generate 15 psig, saturated steam for export. From this exchanger the resid, now cooled to about 300 °F, will be cut using an appropriate cutter stock to meet fuel oil viscosity specifications, and then further cooled before being sent to storage. The HVGO product and pumparound will be heat-exchanged with the crude in exchanger C-127, C-128 and C-160. Pumparound material will be sent through filters for removal of particulates and to the spray header above the HVGO packed section. Product HVGO is pumped by J-129 and heat-exchanged with crude in exchangers C-154 and C-129. Finally, tempered-water cooler C-130 is employed to cool HVGO product to storage temperature of about 175 °F.

Vacuum is maintained by a combination of steam ejectors and vacuum pumps for this case. The first two stages are steam jet ejectors. The third stage is a motor-driven liquid-ring vacuum pump. This configuration results in a reduction in motive steam requirements and a commensurate reduction in sour water production.

6.3.4 Waste Minimization Practices

6.3.4.1 Air Emissions

6.3.4.1.1 Stack Emissions

The atmospheric crude heater and the vacuum heater employ three NO_x control technologies: low NO_x burners, Flue Gas Recirculation (FGR), and SCR. An SO_x reduction unit, namely a wet limestone system, is installed on the atmospheric heater for the fuel oil cases. A reduction in heat duty in the heaters also results in a reduction in stack emissions.

6.3.4.1.2 Fugitive Emissions

The following measures were incorporated in the design of the Case 1 refinery to reduce fugitive emissions:

- Installing leakless valves such as bellows sealed or diaphragm type;

- Installing sealed pumps such as pumps with barrier fluids at higher pressures, pumps with a barrier fluid seal pot which vents to the flare, canned pumps, magnetic drive pumps, or diaphragm pumps;
- Providing relief valves with rupture disks and venting to flare;
- Inspecting flanges during construction and start-up for proper torquing and installing sealing rings on leaky flanges;
- Enclosing distance pieces and venting the crankcase to the flare for compressors;
- Totally closing the sampling systems; and
- Eliminating all VOC to drains with a MDO system.

6.3.4.1.3 Benzene NESHAP and VOC Emissions

A steam stripper is used to treat the desalter effluent. Benzene and other VOC are stripped and returned to the process.

All instruments including level bridles and control valve stations are drained to the MDO system. The MDO system consists of a header which carries the drained liquids to a vessel, where they are separated into fumes, hydrocarbon liquids, and wastewater. Fumes are discharged to the flare or other control device. The liquid hydrocarbons are recycled to the process, and the wastewater is discharged to the sour water stripper or to the desalter steam stripper.

The sewer is constructed to standards required by NSPS Subpart QQQ. Totally-enclosed sampling connections are employed so that no part of any sample would enter the sewer.

6.3.4.2 Wastewater and Stormwater

6.3.4.2.1 Wastewater

Wastewater reductions are achieved by installing a separate water recycle plant to process the water plant sludge, boiler blowdown, boiler feed water treatment effluent, cooling tower blowdown, steam condensate drains, and other mildly-contaminated wastewaters. The wastewater from these sources is collected by a separate drain system. Treated effluent from the water recycle plant is returned for use as cooling water. Contaminated oily water from the process is sent to the refinery wastewater treatment plant (WWTP).

The water recycle facility is a physical-chemical treatment plant comprising a solids contact clarifier with sludge thickening and drying. This facility significantly reduces the volume of wastewater that must be treated in the WWTP. Furthermore, such an operation results in reduced RCRA emissions, as noted below in 6.3.4.3. Although not included in Case 1, a TDS removal unit may also be considered.

6.3.4.2.2 Stormwater

Stormwater minimization practices involve complete separation of the stormwaters by classification:

- Contaminated stormwater is sent to the WWTP for treatment. Contaminated stormwater is stormwater which falls on paved areas within the crude unit ISBL. This stormwater is likely to be contaminated with the free oil or soluble organics and requires treatment prior to discharge to a receiving system.

- Potentially contaminated stormwater is collected, held, tested and released if non-contaminated, or treated in the WWTP if contaminated.

- Uncontaminated stormwater is released to the outfall.

Stormwater segregation requires careful consideration during the design of the system. In most cases, two stormwater systems are required: a clean stormwater system and a potentially contaminated stormwater system.

6.3.4.3 RCRA Hazardous and Solid Wastes

RCRA listed hazardous waste generation rates are reduced significantly by the segregation of the listed wastes from the water treatment sludges and by the installation of the water recycle plant. The water treatment sludges (consisting of water plant sludge, boiler blowdown, boiler feed, water treatment effluent, cooling tower blowdown, steam condensate drains, and other wastes with low level TOC contamination) are purposely segregated from the listed waste streams (K048, K049, K050, and K051). The sludges generated from the various water processes are not allowed to mix with the wastewater streams that produce API separator sludge and oil in the WWTP. The non-contaminated sludges are not listed as hazardous, but are not exempt from the Toxicity Characteristic or other characteristic tests.

The total quantity of non-hazardous solids is increased significantly. This is primarily due to the sludge produced by the SO_x scrubber employed for the three fuel oil cases.

6.4 Chemical and Utility Requirements

The chemical and utility requirements for operations were calculated and are shown in Table 6.1 entitled "Chemical Requirements," and Table 6.2 entitled "Utility Requirements".

6.5 Inventory of Emissions and Effluents

6.5.1 Air Emissions

Fugitive emissions can be virtually eliminated in a new installation by specifying zero-emission equipment. Stack emissions can be reduced with control devices, and further reductions can be achieved by energy conservation. It is axiomatic that the cost for each increment of reduction becomes progressively more expensive.

6.5.1.1 Stack Emissions

As in the Base Case, four fuel cases were analyzed. A summary of all stack emission sources (combustion devices) and rates associated with the model new crude unit are shown in Tables 6.3, 6.4, 6.5, and 6.6, one table for each fuel case. The point sources of air emissions include the process heaters, boilers (emissions caused by energy and steam usage in the crude unit), and the hot oil system which was added to minimize generation of oily condensate.

Stack emissions are reduced by energy conservation measures. Emissions from the two process heaters are reduced by installing control devices for NO_x, and, in the fuel oil cases, by installing a wet limestone SO_x control device. The NO_x control devices consist of SCR units, low NO_x burners, and flue gas recirculation (FGR) systems. An unfortunate side effect of the wet limestone SO_x reduction unit is the production of large quantities of calcium sulfate sludge: theoretically 5.38 lbs of sludge per pound of sulfur removed.

Emission rates of VOC, carbon monoxide (CO), and total suspended particulates (TSP) from the atmospheric and vacuum heaters were calculated using the air emission factors listed in AP-42.

Uncontrolled emission rates of SO_x from the heaters were calculated by applying AP-42 emission factors. A 90% reduction in SO_x emissions was assumed for the fuel oil cases which employ the wet limestone SO_x control device.

For NO_x, factors of 0.06 lbs/MMBTU and 0.12 lbs/MMBTU for fuel gas and fuel oil firing, respectively, were assumed. These represent the commercially available technology for low NO_x burners and compare with the 0.1 lbs/MMBTU for fuel gas firing and 0.2 lbs/MMBTU for fuel oil firing which were used for the Base Case. The SCR unit was assumed to reduce NO_x by 90%. No direct credit was taken for flue gas recirculation. An indirect credit was nevertheless achieved through reduced energy requirements.

6.5.1.2 Fugitive Emissions

Piping fugitive emissions are summarized in Table 6.7. Emissions from the cooling tower were not included in the fugitive emissions calculations.

Table 6.7 shows that fugitive emissions can be 100% controlled. Fugitives from valves are controlled by installing "leakless" valves. Pump emissions are controlled through the use of canned pumps, magnetic drive pumps, diaphragm pumps, or double-seal pumps with a barrier fluid at higher pressure than the pumped fluid or with barrier fluid seal pots which vent to the flare. Relief valves are vented to the flare and protected by rupture disks. Compressor crankcases are vented to the flare, and the distance pieces are enclosed and vented to the flare. Closed loop sampling devices are installed. Liquid drains that contain VOC are routed to the MDO system. Fugitives from flanges are controlled by physical inspection, leak monitoring, and directed maintenance. In addition, leaking flanges are sealed with ring-type sealing device. Welded flanges were deemed to present a maintenance nuisance.

6.5.1.3 Benzene NESHAP

A benzene estimate was prepared for the new model crude unit and is shown in Table 6.8. The estimate is 0.00329 metric tons per year. The only remaining benzene NESHAP emission source within the crude unit battery is the desalter.

This reduction was accomplished by instituting the following methods and designs:

- A steam stripper was added to the desalter effluent line. Benzene and other VOC will be stripped and recycled to the process. The stripper effluent contains 0.005 ppmw of benzene.

- Installation of totally enclosed loops and totally enclosed sampling ports, which eliminate these sources of emissions.

- All level bridles and vessel drains are drained to an MDO system, which recycles all crude, products, and intermediates, and eliminates all emissions.

6.5.1.4 VOC Emissions

Although VOC from routine drains are prevented from entering the sewers, the sewers are constructed to NSPS Subpart QQQ standards. Even in a tightly-controlled environment, provisions for spills and accidents must be made.

6.5.2 Stormwater and Wastewater

6.5.2.1 Stormwater

If a new refinery were to be built, stormwater should be segregated from process water to the greatest extent possible. Thus, all condensate drains, the cooling tower blowdown, boiler water blowdown, and all stormwater from contaminated areas should be diverted from the clean stormwater sewers. Drainage from potentially contaminated areas should be held and tested prior to discharge to the stormwater sewers. In the event of contamination, the wastewater should be discharged to the process sewer or a sewer dedicated to non-oily process water such as cooling tower blowdown. The non-oily process sewer should bypass the API separator and discharge directly to the biological unit to minimize the production of API separator sludges. The adoption of this system should present no difficulties in meeting the NPDES Stormwater Permit limitations.

6.5.2.2 Wastewater

In the model new crude unit as in the Base Case, the wastewater will still be treated in a central WWTP. However, no benzene-containing streams will be allowed to enter the wastewater collection system in Case 1. Steam stripping the benzene-containing streams at the source will remove benzene and most other VOCs that are returned to the process. Sewer construction to NSPS Subpart QQQ standards is still advisable to handle VOC emissions from spills and accidents. The WWTP will require VOC controls on the API separator, but otherwise it will be essentially unchanged from a 1980s treatment plant.

Table 6.9 summarizes the source and quantities of all wastewater produced by the new unit. The total flow of wastewater has been reduced to 339 gpm. The quality of the water is also improved (by comparison with the Base Case), since the discharge contains only permissible amounts of benzene and VOC, and a reduced content of oil, grease, and TSP. Reducing the benzene and VOC content also results in a reduction in BOD, phenols, and sulfides, although this is a side effect of the at-source reduction process rather than an intended end result. The suspended solids produced by chemical reactions between the wastewaters, water plant sludge, cooling tower blowdown, boiler water sludge, boiler blowdown, etc. are eliminated by routing these wastewaters to a recycle plant. The solids from this wastewater plant are treated separately and do not become part of the API separator sludge. Oil and grease from sample drains, instrument drains, and vessel drains are eliminated from the process sewer by re-routing to the MDO system. The flow and O&G values for the desalter are taken from the design information as in the Base Case.

The boiler blowdown, steam condensate loss, cooling tower blowdown, water plant sludge, and boiler water treatment plant discharge rates to the process sewer were estimated using the same techniques and basis as used in the Base Case. The water recycle plant sludge generation rate was estimated at 5% of the influent flow, with a concentration of 5% solids.

The entire 152 gpm of stripped sour water from the crude unit is reused in the desalter; thus, sour water is shown as both a credit and debit on the inventory in Table 6.9.

The desalter is still the major contributor of process wastewater within the crude unit. This wastewater is contaminated with solids, phenols, COD, NH_3, and Sulfides.

6.5.3 RCRA Solid and Hazardous Wastes

In order to minimize the production of RCRA listed hazardous wastes downstream of the crude unit, the water plant sludge, boiler blowdown, boiler feed water treatment effluent, cooling tower blowdown, steam condensate drains, and all other wastewaters with low level Total Organic Carbon (TOC) contamination are collected by a separate drain system and treated in a separate facility designed especially for this purpose. This facility is a physical-chemical treatment plant comprising a solids contact clarifier with sludge thickening and drying. This operation significantly reduces the volume of wastewater that must be treated in the refinery's main wastewater treatment plant.

Quantities of solid and hazardous wastes, except for K050 and other maintenance wastes, were estimated and summarized in Table 6.10.

The water treatment sludges and SO_x scrubber wastes no longer contribute to the generation of RCRA listed hazardous wastes since they are not allowed to enter the oily water sewer. The water treatment sludges and SO_x scrubber wastes may still be classified as hazardous, however, if they exhibit a characteristic. Segregating the water treatment sludges significantly reduces the amount of RCRA hazardous wastes generated by the crude unit.

6.6 Cost Estimate

The same cost estimate basis, qualifications, exclusions and methodology used in the Base Case were applied in Case 1. The costs of the desalter water steam stripper and sewers built to NSPS Subpart QQQ standards were included in this cost estimate. As the overall design approach was oriented toward a model pollution prevention crude unit, the equipment count, equipment type, and equipment sizing for Case 1 are different from the Base Case.

The cost estimate for Case 1 totals $164,342,000.

6.7 Comparison with Base Case

6.7.1 Emissions and Effluents Reductions

Significant reductions in emissions and effluents were achieved in Case 1 when compared with the Base Case. These reductions are outlined below:

- Fossil fuel energy usage was reduced while electricity consumption increased. Energy derived from fossil fuels decreased 17% from 948

MMBTU/hr to 786 MMBTU/hr. Electrical power usage increased 24% from 2670 KW to 3310 KW.

- NO_x emissions were reduced:
  - 71% from 597 tons/year to 172 tons/year for the fuel oil cases,
  - 60% from 415 tons/year to 164 tons/year for the fuel gas case.

- SO_x emissions were reduced:
  - 93% from 7027 tons/year to 493 tons/year for the 3.34% sulfur fuel oil case,
  - 93% from 2105 tons/year to 149 tons/year for the 1.00% sulfur fuel oil case,
  - 93% from 423 tons/year to 31 tons/year for the 0.20% sulfur fuel oil case,
  - 18% from 3.30 tons/year to 2.73 tons/year for the fuel gas case.

- VOC emissions were reduced:
  - 94% from 190 tons/year to 11 tons/year for fuel oil,
  - 97% from 183 tons/year to 5.6 tons/year for fuel gas.

- CO emissions were reduced:
  - 17% from 171 tons/year to 142 tons/year for fuel oil,
  - 18% from 185 tons/year to 152 tons/year for fuel gas.

- TSP emissions were reduced:
  - 30% from 501 tons/year to 353 tons/year for the 3.34% sulfur fuel oil case,
  - 28% from 187 tons/year to 134 tons/year for the 1.00% sulfur fuel oil case,

  - 26% from 80 tons/year to 59 tons/year for the 0.20% sulfur fuel oil case,
  - 17% from 23 tons/year to 19 tons/year for the fuel gas case.

- Fugitive VOC emissions from piping components were reduced from 176 tons/year to 0 tons/year.

- The annual benzene quantity was reduced from 28 Mg/yr to 0.00329 Mg/yr.

- Wastewater generation was reduced 42% from 584 gpm to 339 gpm by process modifications, reduction in energy usage, and recycling.

- RCRA hazardous wastes were reduced 93% from 12,535 ppd to 934 ppd. The quantity of non-hazardous solid waste generation varies with the sulfur content of the fuel oil and increased from 0 ppd for the Base Case to between 5460 ppd and 70,657 ppd.

6.7.2 Technology Used to Achieve Reductions

To achieve the above reductions in environmental emissions from the plant, the following design features were incorporated in the process flow diagrams, the major equipment list, and the cost estimate of Case 1.

6.7.2.1 Pinch Analysis and Heat Exchanger Network Analysis

The crude preheat train is arranged in such a manner that an optimum preheat temperature of 550 °F (110 °F higher than the Base Case) can be achieved with an incremental surface area of 18%. The general rule of thumb is that the rate of return diminishes as the surface area increases. It should be stressed that the incremental surface area is only economical when the capital cost of added surface is lower than the savings in utility and operating costs. In terms of pollution prevention, however, a reduction in fuel usage due to improved energy utilization translates to a direct reduction in pollutant emission rates.

6.7.2.2 Optimum Crude Unit Pumparound Design

In order to minimize energy loss to the atmosphere via air and water cooling, two pumparound exchanger circuits were added to the crude tower. Pumparound heat should be removed at high temperature levels to increase crude preheat in the crude column. Upper section reflux requirements are reduced by the upper and lower pumparound heat removal. Rates are balanced, so that fractionation efficiency is maintained, and the same sidedraw product rates and qualities are achieved.

6.7.2.3 Reboiled Sidestrippers and Hot Oil Heating

Sidedraw products are often stripped via steam-stripping or reboiling to meet a flash point specification or to improve front end fractionation and yield distribution. Stripping steam is normally used to meet flash point specification because it is less costly compared with indirect reboiling. However, there are inherent problems associated with using stripping steam, such as occasional off-spec products caused by high moisture contents and crude column upsets caused by excessive usage of stripping steam. Salt driers are required downstream of the sidestrippers to meet moisture or haze specifications. Case 1 utilizes reboiled sidestrippers without direct steam contact for the Naphtha, Kerosene and HDF sidedraw products. Furthermore, salt disposal problems are eliminated as there is no longer a requirement for salt driers. The sour water loads to the sour water stripper are reduced by eliminating stripping steam to three of the four sidestrippers.

A heat transfer fluid heating (hot oil) system is preferable to using steam for reboiling because there is no requirement for chemical treatment and blow down from a self-contained, hot oil recirculation system. Instead of process-to-process heating, Case 1 utilizes hot oil heating for the three sidestripper reboilers. Lower sidedraw pumparounds and hot products are used to preheat the crude charge instead. To eliminate heat exchanger cleaning sludge disposal problems, stab-in reboilers can be considered for the sidestrippers.

6.7.2.4 Lower Vacuum Column Flash Zone Pressure

As the flash zone pressure is reduced to 20 mmHgabs, a net reduction of 20 MMBTU/hr in the vacuum heater total duty is realized. At atmospheric or higher pressure, the gas oil distillate can not be flashed out of the reduced crude without resorting to a high temperature resulting in a cracking reaction. By carrying out the operation under vacuum, the temperature required for gas oil vaporization is lowered to a degree that minimizes cracking effects.

Removal of steam injection into the process results in a dry vacuum tower operation and lower operating costs. Vacuum is created by evacuation using steam ejectors, vacuum pumps, or a combination of the two. Vacuum pumps are more efficient than ejectors, but also more expensive. The extra steam required for three-stage ejectors carry more hydrocarbon into the hotwell, thus increasing the oil load on the sewer system. Those hydrocarbons condense with the steam and add to potential oil reclamation or pollution problems. In Cases 1 and 2, the third stage steam ejector is replaced with a liquid ring vacuum pump.

6.7.2.5 Low NO_x Burners and NO_x Selective Catalytic Reduction (SCR) Unit

New generation low NO_x burners can achieve emission rates of 0.06 lb/MMBTU. The gas-fired hot oil heaters selected for Cases 1 and 2 are equipped with new low NO_x burners with flue gas recirculation. The NO_x level expected to be certified by equipment vendors is 30 ppm for fuel gas firing. Low NO_x burner design and development is a very active field, and even lower NO_x levels may be achievable by press time of this report.

Even though low NO_x burners are used in the crude and vacuum furnaces, it is estimated that NO_x emission rates will be higher than 0.06 lbs/MMBTU for fuel gas firing. A SCR unit with ammonia injection will be utilized to remove the NO_x by 90% (refer to PFD P-7011-D, schematic C). Field-proven for several years, this process is widely accepted as an effective control technology based on preferential reduction selectivity of ammonia for NO_x.

$$4NH_3 + 4N0 + 0_2 \xrightarrow{\text{catalyst}} 4N_2 + 6H_20$$

$$4NH_3 + 2N0_2 + 0_2 \xrightarrow{\text{catalyst}} 3N_2 + 6H_20$$

Careful design precautions are taken to monitor burner control management, excess 0_2, fuel gas NO_x levels, and NH_3 breakthrough. Soot blowers are equipped with the furnaces for intermittent usage. This will normally minimize pluggage due to flyash deposits on the air-preheat exchangers. Also down-flow arrangement for the SCR reactor can be considered.

Ammonia slip in SCR units occurs at greater than 90% removal range. Removal efficiencies of 80-90% can be achieved with negligible ammonia slip. Highly resistant to SO_3 poisoning, vanadium oxide on a titanium oxide base catalysts can be utilized in the SCR reactor preceded by proper ammonia vaporization and injection control. Catalyst vendors will guarantee the catalyst performance for three years or more. The spent catalysts can be returned to the suppliers for re-conditioning on a "take-back" basis. This will eliminate any on-site spent catalyst disposal problems.

6.7.2.6 Minimum Discharge By Sidestream Softening

The proposed process scheme, as depicted in figure A (Dwg. P-7010-D), involves routing the cooling water blowdown, boiler feedwater blowdown, and demineralized water regenerants to a centralized softening unit for scale removal. This will provide zero liquid discharge from the crude and vacuum unit. The sidestream softener uses inexpensive chemicals such as lime and soda ash, and the softening technology is well established. The process removes calcium, magnesium carbonate, and silica (calcium precipitates as calcium carbonate, magnesium as magnesium hydroxide, and the silica is absorbed on the magnesium hydroxide).

The treated effluent can then be returned to the cooling tower as makeup. This will reduce fresh water makeup requirements and eliminate any liquid discharge from the crude and vacuum unit.

The dissolved and suspended materials are converted to a solid sludge for on-site landfill disposal (approved Class 2 landfill). As a corrosion inhibitor, sodium molybdate works well with the zero discharge scheme, and imposes considerably less environmental impact than zinc and chromate. It is estimated that 5% by volume of the sidestream softener blowdown will turn into a non-hazardous sludge.

6.7.2.7 Controlling Fugitive Emissions

6.7.2.7.1 Relief Valves

To eliminate emissions from relief valves, relief valves discharge to the refinery flare and a rupture disk is installed upstream of each relief valve in hydrocarbon service. Full protection can be provided by dual relief valves and a rupture disk.

6.7.2.7.2 Valves

Leakless bellows, diaphragm, or valves with precompressed graphite or teflon ring backing built per API 598 valves are used. Quarter-turn valves such as plug, ball, and butterfly valves are proposed as long as pressure and temperature limitations are not exceeded. For severe service application, live loaded graphite packing should be used for sliding stem valves.

6.7.2.7.3 Pump Seals

Canned, magnetic drive, and diaphragm pumps are leakless. Pumps with double mechanical seals are leakless if the barrier fluid is at higher pressure than the pumped fluid, or if the barrier fluid seal pot vents to flare. Sealless magnetic drive pumps for < 50 hp services are proposed.

6.7.2.7.4 Flanges

Flanged connections can be minimized during the design stage. Where welded connections are not practicable, flanges should be closely inspected during construction to ensure that proper gaskets are installed and torque specifications are maintained. The flanges should be inspected during start-up for leaks. Leakers will be eliminated by regasketing, retorquing, or, where necessary, installing sealing rings. All these operations should be performed before insulating around the flanges.

6.7.2.8 Desalter Water VOC Removal Stripper and Sour Water Stripper Bottoms Reuse

6.7.2.8.1 Benzene Removal

A packed column is proposed for removing VOC by flash distillation and entrainment separation. It was estimated that the water discharge from the desalters contains a maximum of 20 ppm benzene, and the quantity of desalter wash water is equivalent to 4-8 volume% of the crude charge. All benzene is removed by steam stripping to an overhead condenser (refer to P-7010-D, schematic B). After decanting, the recovered benzene can be transferred to the gasoline blending station. The discharge from the stripper bottoms, with benzene levels in the 20 ppb range, is routed to the waste water treatment system. A brine de-oiling vessel is installed ahead of the packed column to decant any free oil undercarry from the desalter. Acid injection is employed to spring oil from emulsions.

6.7.2.8.2 Phenol Removal and Stripped Water Reuse

The Outside Battery Limits (OSBL) sour water stripper (not shown in PFD's) removes most of the hydrogen sulfide and ammonia from refinery process waters so that the water can be reused or safely discharged. Sour water stripper bottoms can be considered for use in the desalter as wash water in ratios of 4 to 8 percent of crude. Better than 50% phenol removal by desalted crude can be achieved in the desalter by mixing the phenol-laden sour water stripper bottoms with incoming crude. If crude contains high concentrations of naphthenic acids, the pH of stripped water should be maintained at neutral or slightly acidic to avoid formation of ammonium naphthenate soaps, which are emulsion stabilizers that prevent adequate water and oil separation in the desalters.

6.7.2.9 Advanced Process Control

6.7.2.9.1 Control Systems

A new generation distributed control systems (DCS) is implemented for the new crude and vacuum unit. A minicomputer provides calculation capability for more sophisticated advanced control algorithms and energy and material balances. Both crude and vacuum distillation columns can be configured for distributed control, with column optimizer software residing in the process computer.

6.7.2.9.2 Process Monitors

Process gas chromatograph (GC) will be used to monitor the crude and vacuum tower distillation performance by providing near-real-time stream composition and calculated parameter information. Improved distillation control can be achieved by on-line GC control. This would result in savings and off-spec product reduction. A distributed process GC system with composition control hierarchy and supervisory control is coupled with a DCS. A minicomputer monitors GC status and verifies composition information validity prior to performing calculations and control. In general, direct GC control provides the following benefits:

- Reduce recycle due to reprocessing of off-spec product.
- Reduce energy consumption by minimizing over-fractionation.
- Improve profitability by minimizing higher-value product giveaway in lower-value product.
- Minimize waste by maintaining satisfactory product quality.
- Provide yield enhancements.
- Increase unit throughput.

6.7.2.9.3 Emission and Effluent Monitoring

Emphasis is placed on pollution monitoring equipment selection, maintenance programs, and emissions reporting requirements. Monitors are placed in appropriate locations for communicating with the minicomputer for process control, alarm annunciation, data acquisition, and automatic data reporting. Multiple component process chromatographs and mass spectrometers are utilized to provide continuous single or multiple component analysis for air and water quality. A complete spectrum of pollution monitoring is provided for the following areas:

- Ambient air monitors at plant perimeter for airborne pollutants.
- NO_x, NH_3, SO_x, CO, O_2, and TSP concentrations and opacity in flue gas.
- Benzene levels at the API separator.
- TOC, turbidity, free available chlorine, and hydrocarbon detection in cooling water return header.
- Turbidity, TDS, pH, hardness, organics, ions, chloride, sulfate, conductivity, alkalinity, silica, Dissolved Oxygen, and colorimeter readings are required for incoming water and effluents.
- Area VOC monitors in vicinity of vacuum system
- VOC stripper/analyzers for plant water effluents.
- Groundwater monitoring near lined ponds and cooling tower basin.

To facilitate the pollution monitoring activities, extra personnel will be required for maintaining all the hardware associated with GC, analyzers, and process computer. An application engineer is required for preparing software and communication link between the computer and all the microprocessor-controlled GC's. Additional staff may be required to obtain accurate meaningful measurements and to analyze results.

6.8 Cost/Benefit Analysis of Environmental Upgrades

Costs and benefits of the pollution prevention ideas employed in Case 1 are analyzed in Tables 6.11, 6.12, and 6.13. These tables should not be considered a complete cost benefit analysis, but, rather, an attempt to relate the capital cost of the change and the direct, known, and tangible benefits that accrue to the refinery.

Some costs are not easy to describe in monetary terms. Costs can include non-monetary burdens such as reduced operational flexibility, increased maintenance and reporting requirements, and increased training requirements. Benefits can also be described in monetary and non-monetary terms. Monetary benefits include reduced energy requirements and lower worker health care costs. Non-monetary benefits include reduced emissions, corporate neighbor good will, increased safety, increased process knowledge, and decreased worker exposure to toxic or hazardous materials. Indirect benefits such as cleaner air and increased public health are likewise not considered as the measurement of these impacts is beyond the scope of the study.

Table 6.11 summarizes the annualized cost of NO_x, VOC, and SO_x removal per ton of net emission reduction. The annualized cost for NO_x net emission reduction is based on installing two SCR units (one for the Atmospheric Crude Heater and one for the Vacuum Heater) to reduce NO_x emissions by 90%. The annualized cost for VOC net emission reduction is based on the costs for multiple pump seals, upgraded valves/flanges, MDO system, and benzene removal stripper. SO_x control will not be required while burning fuel gas because of low emission levels. However, for burning fuel oil, the SO_x levels can be reduced 90% with a limestone scrubber. Refer to Appendix J for details of the cost calculations.

As illustrated in Tables 6.12 and 6.13, capital investment for some ideas (here, heat integration changes and adding a vacuum pump) can actually be justified and pay out in energy savings. In these instances, net reductions in emissions can be achieved at no cost.

6.9 Summary and Conclusions

The total fossil fuel energy use for Case 1 is 786 MMBTU/hr. The electricity usage is 3310 KW with the SO_x scrubber and 3153 KW without the scrubber.

The air emissions for Case 1 are summarized in Table 6.14. SO_x and TSP emissions increase proportionally with increasing sulfur content of the fuel. Burning fuel oil increases NO_x emissions compared to fuel gas.

Table 6.14 includes 0 tons/year of fugitive VOC emissions.

The total annual benzene quantity for the Case 1 crude unit is 0.00329 metric tons/year.

Total wastewater flow produced by the crude unit is 339 gpm. The wastewater contains 119 gals/day of oil and grease, 5460 lbs/day of suspended solids, 4571 lbs/day of COD, 572 lbs/day of NH_3, 131 lbs/day of sulfides, and 199 lbs/day of phenols.

Between 5460 ppd and 70,657 ppd of non-hazardous solid waste are produced depending on fuel type. The least amount of non-hazardous solid waste is produced by burning fuel gas and the most by burning 3.34% sulfur fuel oil. A total of 934 lbs per day of RCRA solid hazardous wastes is produced.

TABLE 6.1

CASE 1
CHEMICAL REQUIREMENTS

User Chemical	Chemical Requirements	
Desalter Water		
Sulfuric Acid	6.0	GPH
Crude Charge		
Caustic	0.5	GPH
Crude Tower		
Ammonia	10.0	LB/HR
Corrosion Inhibitors	0.7	GPH
Vacuum Tower		
Ammonia	3.0	LB/HR
SCR		
Ammonia (theoretical)	21.79	LB/HR
Catalyst	800	ft^3/yr
West Limestone Scrubber (fuel oil firing in B-101 only)		
CaCO3 (theoretical)	1,578	LBS/HR w/ 3.34 wt% S fuel
CaCO3 (theoretical)	472	LBS/HR w/ 1.0 wt% S fuel
CaCO3 (theoretical)	94	LBS/HR w/ 0.2 wt% S fuel
Cooling Tower		
Sodium Molybdates	0.01-0.05	GPH
Dispersant	0.06	GPH
Biocide	0.2- 0.4	LBS/HR
Chlorine	40	LBS/HR
Sulfuric Acid	3 - 5	LBS/HR

TABLE 6.2

CASE 1
UTILITY REQUIREMENTS

Cooling Water Circulation	17,370	GPM
Electricity Consumption	3,310	KW with SOx Scrubber
	3,153	KW without Scrubber
Fossil Fuel	786	MMBTU/hr
Steam		
500# Consumption	120,010	LBS/HR
Production	120,010	LBS/HR (1)
125# Consumption	116,261	LBS/HR
Production	53,240	LBS/HR
50# Consumption	29,900	LBS/HR
Production	11,784	LBS/HR
15# Consumption	10,000	LBS/HR
Production	92,030	LBS/HR

(1) From steam boilers in utility area.

TABLE 6.3

CASE 1
AIR EMISSIONS
(FUEL GAS CASE)

EMISSION SOURCE	DESCRIPTION	HEAT RELEASE (MMBTU/HR)	AIR EMISSIONS (Tons/Year)				
			NO_x	CO	VOC	TSP	SO_2
FUEL GAS							
B-102	Vacuum Heater	130	3.42	25.31	0.39	3.16	0.45
OSBL	Boilers	325	142.35	63.27	2.21	7.91	1.13
B-103	Hot Oil System	40	10.51	6.81	0.55	0.97	0.14
B-101	Atmospheric Heater	291	7.65	56.65	1.98	7.08	1.01
	Total Energy	786					
	ANNUAL STACK EMISSIONS		163.93	152.03	5.63	19.13	2.73
	ANNUAL FUGITIVE EMISSIONS (from Table 5.9a)		0	0	0	0	0
	TOTAL ANNUAL AIR EMISSIONS		163.93	152.03	5.63	19.13	2.73

TABLE 6.4

CASE 1
AIR EMISSIONS
(0.2% FUEL OIL CASE)

EMISSION SOURCE	DESCRIPTION	HEAT RELEASE (MMBTU/HR)	AIR EMISSIONS (Tons/Year)				
			NO_x	CO	VOC	TSP	SO_2
FUEL GAS							
B-102	Vacuum Heater	130	3.42	25.31	0.89	3.16	0.45
OSBL	Boilers	325	142.35	63.27	2.21	7.91	1.13
B-103	Hot Oil System	40	10.51	6.81	0.55	0.97	0.14
FUEL OIL							
B-101	Atmospheric Heater	291	15.29	46.86	7.12	46.86	29.43
	Total Energy	786					
	ANNUAL STACK EMISSIONS		171.57	142.25	10.77	58.90	31.15
	ANNUAL FUGITIVE EMISSIONS (from Table 5.9a)		0	0	0	0	0
	TOTAL ANNUAL AIR EMISSIONS		171.57	142.25	10.77	58.90	31.15

TABLE 6.5

CASE 1
AIR EMISSIONS
(1.0% FUEL OIL CASE)

EMISSION SOURCE	DESCRIPTION	HEAT RELEASE (MMBTU/HR)	AIR EMISSIONS (Tons/Year) NO_x	CO	VOC	TSP	SO_2
FUEL GAS							
B-102	Vacuum Heater	130	3.42	25.31	0.89	3.16	0.45
OSBL	Boilers	325	142.35	63.27	2.21	7.91	1.13
B-103	Hot Oil System	40	10.51	6.81	0.55	0.97	0.14
FUEL OIL							
B-101	Atmospheric Heater	291	15.29	46.86	7.12	121.83	147.14
	Total Energy	786					
	ANNUAL STACK EMISSIONS		171.57	142.25	10.77	133.88	148.86
	ANNUAL FUGITIVE EMISSIONS (from Table 5.9a)		0	0	0	0	0
	TOTAL ANNUAL AIR EMISSIONS		171.57	142.25	10.77	133.88	148.86

TABLE 6.6

CASE 1
AIR EMISSIONS
(3.34% FUEL OIL CASE)

		HEAT	AIR EMISSIONS (Tons/Year)				
EMISSION SOURCE	DESCRIPTION	RELEASE (MMBTU/HR)	NO_x	CO	VOC	TSP	SO_2
FUEL GAS							
B-102	Vacuum Heater	130	3.42	25.31	0.89	3.16	0.45
OSBL	Boilers	325	142.35	63.27	2.21	7.91	1.13
B-103	Hot Oil System	40	10.51	6.81	0.55	0.97	0.14
FUEL OIL							
B-101	Atmospheric Heater	291	15.29	46.86	7.12	341.14	491.44
	Total Energy	786					
	ANNUAL STACK EMISSIONS		171.57	142.25	10.77	353.18	493.17
	ANNUAL FUGITIVE EMISSIONS (from Table 6.7)		0	0	0	0	0
	TOTAL ANNUAL AIR EMISSIONS		171.57	142.25	10.77	353.18	493.17

TABLE 6.7

CASE 1
FUGITIVE VOC EMISSIONS CALCULATIONS

SOURCE	STREAM COMPOSITION	NUMBER OF SOURCES	AP-42 EMISSION FACTOR (LB/HR/SOURCE)	CONTROL METHOD	CONTROL EFFICIENCY %	CONTROLLED EMISSION (LB/HR)	CONTROLLED EMISSION (TON/YR)
Valves	gas	272	0.059	note 1	100	0	0
	light liquid	199	0.024	note 1	100	0	0
	heavy liquid	1331	0.0005	note 1	100	0	0
Pump Seals	light liquid	10	0.025	note 2	100	0	0
	heavy liquid	32	0.046	note 2	100	0	0
Flanges	gas	347	0.00056	note 3	100	0	0
	light liquid	283	0.00056	note 3	100	0	0
	heavy liquid	2452	0.00056	note 3	100	0	0
Open-Ended Valves		489	0.005	note 4	100	0	0
Relief Valves		37	0.059	note 5	100	0	0
Compressor Seals		3	1.6	note 6	100	0	0
Drains		126	0.07	note 7	100	0	0
Sample Connections		24	none	note 8	100	0	0
			TOTAL FUGITIVE EMISSIONS			0	0

NOTES:

1. **Use leakless valves.**
2. **Use sealless pumps or pumps with double seals.**
3. **Minimize flanges, inspect and install sealing rings on leakers.**
4. **Plug, blind, or cap open end.**
5. **Discharge to flare.**
6. **Recycle to process, enclose distance pieces, and vent crankcase to flare.**
7. **Hard pipe to Maintenance Drain Out system.**
8. **Totally closed loop sampling.**

TABLE 6.8

CASE 1 AND 2
BENZENE NESHAP EMISSIONS ESTIMATE

SOURCE	WATER OR ORGANIC	CONTROL METHOD	FLOW (GPM)	ESTIMATED BENZENE CONC. (PPMW)	ANNUAL EMISSIONS (MG/YR)
DESALTER EFFLUENT	Water	Steam Strip	331	0.005	0.0033
SAMPLING POINTS	Organic	Closed Loop	0	5000	0
LEVEL BRIDLES	Organic	MDO	0	5000	0
	NUMBER	SHUTDOWNS PER YEAR	DRAIN (GPY)		
VESSEL DRAINS					
COLUMNS	2	0.25	0	5000	0
EXCHANGERS	66	2	0	5000	0
FIRED HEATERS	3	1	0	5000	0
PUMPS	42	2	0	5000	0
VESSELS	11	0.5	0	5000	0
		TOTAL ANNUAL BENZENE EMISSION ESTIMATE			0.0033

TABLE 6.9

CASE 1
WASTEWATER INVENTORY

		POLLUTANT CONCENTRATIONS (PPMW)							MASS FLOW (LBS/DAY EXCEPT O&G IN GALS/DAY)						
SOURCE	FLOW GPM	OIL & GREASE	TSS	BOD	COD	NH_3	SULFIDES	PHENOL	OIL & GREASE	TSS	BOD	COD	NH_3	SULFIDES	PHENOL
DESALTER EFFLUENT	331	250	150	300	1150	144	33	50	119.16	596.28		4571.45	572.43	131.18	198.76
SAMPLING DRAINS	0								0						
INSTRUMENTS	0								0						
VESSEL DRAINS	0								0						
WATER RECYCLE PLANT SLUDGE	8.1		5000				0	0		4863.89					
SOUR WATER TO SOUR WATER STRIPPER	152														
STRIPPER SOUR WATER TO DESALTER	-152														
TOTALS	339.1								119.16	5460.17		4571.45	572.43	131.18	198.76

TABLE 6.10

CASE 1
SOLID AND HAZARDOUS WASTE INVENTORY

Waste	Quantity (tons/day)
Hazardous Wastes (Note 1)	
Oil and Grease	0.5
Non-Hazardous Wastes	
Sludge (except SOx Scrubber Sludge)	2.7
SO_x Scrubber Sludge	
Fuel Gas	0
0.2% Sulfur Fuel Oil	2.0
1.0% Sulfur Fuel Oil	9.8
3.34% Sulfur Fuel Oil	32.6

Note 1: Does not include K050 or other maintenance wastes.

TABLE 6.11

CASE 1
NET EMISSION REDUCTION ANNUALIZED COST ANALYSIS

Case 1	NO_x	VOC	SO_2
net emission reduction, t/y			
fuel gas	100	176	n/a
fuel oil 1 wt % S	168	176	1,324
annualized cost, $/ton			
fuel gas	28,428	5,106	n/a
fuel oil 1 wt % S	20,031	5,106	1,637

TABLE 6.12

CASE 1
HEAT INTEGRATION OF CRUDE PREHEAT

Base Case:

	Total Installed Cost $
Crude Preheat Exchangers	$ 24,706,000
Crude Furnace	$ 8,690,000
	$ 33,396,000

Case 1:

	Total Installed Cost $
Crude Preheat Exchangers	$ 41,094,000
Crude Furnace	$ 6,714,000
	$ 47,808,000
Delta TIC (Case 1 - Base Case)	$ 14,412,000

Fuel Savings

	Duty, MMBTU/Hr	Cost $/Yr
Base Case	415.9	$ 9,894,000
Case 1	290.6	$ 6,983,000
Delta (Base Case - Case 1)	125.3	$ 2,911,000

Payout = $14,412,000/$2,911,000/yr
= 4.8 yrs.

TABLE 6.13

CASE 1
STEAM JET EJECTORS
VS.
STEAM JETS (2 STAGES) AND LIQUID RING VACUUM PUMP (3RD STAGE)

Base Case:

Three Stage Jets
Total Installed Cost = $3,325,000

Utility Costs:		$/Yr
150 psi steam	46,200 Lb/Hr	$ 1,917,300
Cooling Water	3,929 GPM	$ 196,000
Utilities for 3 stage jets		$ 2,113,300

Case 1:

Two Stage Jets and One Stage Vacuum Pump
Total Installed Cost = $ 5,250,000

Utility Costs:		$/Yr
150 psi steam	32,150 Lb/Hr	$ 1,334,000
Cooling Water	4,429 GPM	$ 220,700
Power	197 KW	$ 114,500
Utilities for jets & vacuum pump		$ 1,669,200

Payout = delta TIC / delta utility costs
(5,250,000 - 3,325,000) / (2,113,300 - 1,669,200)
$ 1,925,000 / $444,100/Yr.

= 4.3 yrs.

TABLE 6.14

CASE 1
SUMMARY OF AIR EMISSIONS

(Tons/year)

FUEL	NO_x	CO	VOC	TSP	SO_x
Fuel Gas	164	152	5.6	19	2.7
Fuel Oil					
0.2% Sulfur	172	142	11	59	31
1.0% Sulfur	172	142	11	134	149
3.34% Sulfur	172	142	11	353	493

Section 7: REVAMP OF CONVENTIONAL CRUDE UNIT (CASE 2)

7.1 Introduction

Case 2 is a study of how the Base Case crude unit can be revamped to incorporate pollution prevention ideas. Whereas Case 1 began as a blank sheet of paper, Case 2 begins with the existing Base Case crude unit. A revamp does not enjoy the same freedom of design available to a model new unit. Therefore, Case 2 considers the technical, physical, and economic constraints which inhere to an existing facility. Incorporation of all the pollution control measures discussed in Case 1 is impractical from the standpoint of constructability and cost. Only ideas that were commercially proven and capable of being implemented during a scheduled turnaround period were considered for Case 2.

7.2 Design Basis

The crude feed, crude type, and product slate remain the same as in the Base Case. Case 2 utilizes some of the same pollution prevention ideas that were developed and implemented for the Case 1 model new crude unit design. These ideas are listed below:

- Use pinch analysis to modify the crude preheat train to increase crude preheat temperature and minimize heat losses to cooling water and air. Equipment and piping relocation are kept to a minimum.

- Reboil three atmospheric column sidestrippers with hot oil. Install two new sidestrippers and modify one existing sidestripper.

- Replace the third stage steam jet ejector with a liquid ring vacuum pump. Two additional steam ejectors, each installed in parallel with one existing stage, are required to achieve the desired operating pressure. The total steam usage in the ejector system of Case 2 is essentially identical to that of Case 1.

- De-oil desalter brine and strip for benzene removal.

- Install new generation low NO_x burners, Flue Gas Recirculation (FGR), and Selective Catalytic Reduction (SCR) units for post-combustion NO_x abatement.

- Use limestone scrubbing of flue gas for SO_x removal when burning high sulfur fuel oil.

- Optimize water reuse by applying minimum discharge techniques.

- Install analyzers to monitor discharges.

- Specify double seals when replacing pumps.

- Implement an inspection & maintenance (I&M) program to reduce fugitive VOC emissions from piping components.

- Blind flange all vents and drains.

- Modify compressors to reduce emissions.

- Apply advanced process control to continuously monitor and optimize energy usage.

- Minimize flanges.

- Install a maintenance drain-out (MDO) system.

- Totally close loop all samplers.

7.3 Process Description

Refer to Appendix D for process flow diagrams (P-7007/7008/7009-D).

7.3.1 Crude Preheat Train

This section highlights the differences between the crude preheat train of Case 2 and the other two cases.

Crude is first heated to 152 °F by exchanger C-101. Next, the new exchanger, C-302, provides crude heat from HVGO product. The sequence of crude heat exchange downstream of the new exchanger was modified from the Base Case by piping rearrangement and addition of valving. The crude first exchanges heat in C-107 against Heavy Distillate Fuel, then returns to C-103, where it exchanges heat with Naphtha Pumparound. Next the crude is heated in exchanger C-129 against HVGO. After desalting, the crude pressure is boosted by pump J-102 to prevent flashing in subsequent exchangers as crude preheating continues. A new exchanger, C-209, was added to effect additional heat exchange with vacuum resid. As in the Base Case, C-109 provides crude heat from AGO product. C-309 was added to this revamp for additional heat recovery from HDF product.

The crude is split into two equal-flow branches, exchanging heat in C-106 and C-128 with HDF Pumparound and HVGO Pumparound, respectively. The sequence of the final two exchangers in the train was switched by piping modifications and addition of isolation valves. C-127 effects heat exchange between crude and HVGO Pumparound, while C-131 effects heat exchange between crude and vacuum resid.

The crude temperature from this revamp preheat train is 474 °F (winter conditions) or 490 °F (summer conditions). These are a full 50 °F higher than the corresponding Base Case temperatures.

7.3.2 Crude Distillation

The Atmospheric Crude Tower of Case 2 operates in a similar manner as that described in the Base Case. Since this case represents a revamp to the existing unit (Base Case), no changes were made to the crude tower configuration. Two pumparounds are maintained, one on HDF and one on Naphtha.

As in Case 1, the sidestrippers for the Naphtha, Kerosene, and HDF products are reboiled with hot oil rather than steam stripped. This change requires more trays in the side strippers to meet desired product specifications. For this reason, two new side strippers were added to achieve identical product specifications as the Base Case.

7.3.3 Vacuum Distillation

In addition to new heat integration into the vacuum tower resid and HVGO Pumparound, the overhead jet system was modified to include one new liquid ring vacuum pump. As in Case 1, this reduces the quantity of sour water produced in the unit, and shifts the utility load from steam to electrical power. The flash zone conditions are the same as in Case 1, 20 mmHgabs.

Re-rating of the vacuum tower is required to ensure adequate operability at the lower pressure of 20 mmHgabs. Additional modifications to the overhead system may also be required to accommodate the new low pressure conditions.

7.3.4 Waste Minimization Practices

7.3.4.1 Air Emissions

7.3.4.1.1 Stack Emissions

SCR units were installed for NO_x control on the atmospheric and vacuum heaters for all fuel cases. A wet limestone scrubbing system for SO_x control was installed on the atmospheric heater for the fuel oil cases.

The existing burners were replaced with new generation low NO_x burners. FGR was retrofitted to control NO_x emissions.

The energy conservation methods described earlier also contributed to a reduction in stack emissions.

7.3.4.1.2 Fugitive Emissions

Fugitive emissions were minimized by the following measures:

- Implement a stringent I&M program for piping components.
- Use leakless valves when replacing small valves where economical.
- Install graphite or teflon packing and seals when repairing valves.
- Specify double seals when replacing pumps.
- Equip relief valves with rupture disks and vent to the refinery flare.
- Enclose compressor distance pieces and vent the crankcase to the flare.
- Totally close loop the sampling systems.
- Eliminate VOCs to drains with a MDO system.

Welding of flanges was not considered because of cost and constructability issues. Only a modest reduction in VOC emissions can be realized by welding existing flanges. A flange I&M program was implemented instead to reduce fugitive emissions.

7.3.4.1.3 Benzene NESHAP and VOC Emissions

A steam stripper was added to the desalter effluent. Benzene and other VOCs are stripped and returned to the process.

All instruments including level bridles and control valve stations were drained to a new MDO system. The MDO system consists of a header to drain liquids into a vessel. Drained liquids are separated into fumes, hydrocarbon liquids, and aqueous waste. The fumes are discharged to the flare or other control device. The hydrocarbon liquids are recycled to the process, and the wastewater is discharged to the sour water stripper or to the desalter steam stripper.

Sampling connections were modified by installing totally closed systems so that no part of any sample can enter the sewer. The sewer system was modified to meet VOC standards as required by NSPS Subpart QQQ. Since all benzene-containing streams are collected and treated at source, the sewers need not be reconstructed to NESHAP standards.

7.3.4.2 Stormwater and Wastewater

7.3.4.2.1 Stormwater

Stormwater minimization practices and facilities are outside the battery limits of the crude unit and hence outside the scope of this study. However, all refineries will be subject to stormwater NPDES regulations.

7.3.4.2.2 Wastewater

Wastewater reductions were achieved by installing a new separate water recycle plant to process the water plant sludge, boiler blowdown, boiler feed water treatment effluent, cooling tower blowdown, steam condensate drains, and all other mildly-contaminated wastewater. The wastewater from these sources is collected by a separate drain system.

The water recycle facility is a physical-chemical treatment plant comprising a solids contact clarifier with sludge thickening and drying. This facility significantly reduces the volume of wastewater that must be treated by the wastewater treatment plant. Furthermore, such an operation results in reduced RCRA emissions, as noted below. Although not included in Case 2, a TDS removal unit may be desirable case-by-case.

7.3.4.3 RCRA and Solid Wastes

RCRA waste generation rates were reduced significantly by the addition of the water recycle plant. With the water recycle plant in the Case 2 crude unit, non-hazardous sludges generated by the various water processes will not be allowed to mix with the hazardous API sludge and oil in the refinery WWTP. Therefore, the non-contaminated sludges are not classified as hazardous, as in the Base Case.

However, the total quantity of non-hazardous solids is significantly higher than in the Base Case. This is partly explained by the segregation of the hazardous and non-hazardous wastes, but primarily it is due to the sludge produced by the SO_x control unit employed for the three fuel oil cases.

7.4 Chemical and Utility Requirements

The chemical and utility requirements for Case 2 are shown in Tables 7.1 and 7.2 respectively.

7.5 Inventory of Emissions and Effluents

7.5.1 Air Emissions

On a mass basis, air emissions are the largest classification of emissions. Fugitive VOC emissions can be reduced significantly in an existing unit by implementing an I&M program and upgrading existing hardware on an ongoing basis. Stack emissions can be reduced with control devices, and further reductions can be achieved through energy conservation. It is axiomatic that the cost for each increment of reduction becomes progressively more expensive.

7.5.1.1 Stack Emissions

As noted in Section 5, four fuel cases were analyzed. A summary of all stack emission sources (combustion devices) and emission rates associated with the revamped crude unit are shown in Tables 7.3, 7.4, 7.5, and 7.6, one table for each fuel case. The point sources of air emissions include the process heaters, offsite boilers (emissions caused by energy and steam usage in the crude unit), and the hot oil system which was added to minimize steam usage.

Stack emissions were reduced by energy conservation measures. Emissions from the two process heaters were further reduced by installing control devices for NO_x, and, in the fuel oil cases, by installing a wet limestone SO_x control device. The NO_x control devices are SCR units, low NO_x burners, and flue gas recirculation (FGR) systems. An unfortunate side effect of the wet limestone SO_x reduction unit is the production of large quantities of calcium sulfate sludge: theoretically 5.38 lbs of sludge per pound of sulfur removed.

Emission rates of volatile organic compounds (VOC), carbon monoxide (CO), and total suspended particulates (TSP) from the atmospheric and vacuum heaters were calculated using the air emission factors in AP-42.

Emission rates of SO_x from the heaters were calculated by applying the AP-42 formula. A 90% reduction in SO_x emissions was assumed for the fuel oil cases which employ the wet limestone SO_x control device.

For NO_x, factors of 0.06 lbs/MMBTU and 0.12 lbs/MMBTU for fuel gas and fuel oil firing, respectively, were assumed. These represent vendor advertised performance for new generation low NO_x burners and compare favorably with the 0.1 lbs/MMBTU for fuel gas firing and 0.2 lbs/MMBTU for fuel oil firing which were used for the Base Case. The SCR unit was assumed to reduce NO_x by 90%. No additional credit was taken for FGR. An indirect credit was achieved through reduced energy requirements.

7.5.1.2 Fugitive Emissions

Fugitive VOC emissions from piping components were calculated by the same general procedure used in the Base Case. Three levels of Inspection & Maintenance (I&M) programs were considered for Case 2. The fugitive VOC emissions resulting from each of the three I&M programs are shown in Tables 7.7.a, 7.7.b, and 7.7.c. Emissions from the cooling tower were not included in the fugitive emissions calculations.

I&M programs can be distinguished by three criteria: the frequency of monitoring, the definition of a leak, and whether maintenance is directed or non-directed. Table 7.7.a reflects a typical I&M program using quarterly monitoring, a 10,000 ppm leak definition, and non-directed maintenance. Table 7.7.b reflects a tougher I&M program using monthly monitoring, a 10,000 ppm leak definition, and directed maintenance. Table 7.7.c reflects a stringent I&M program using quarterly monitoring, a 500 ppm leak definition, and directed maintenance. A refinery's selection of an I&M program is obviously a case-by-case decision. For the purpose of the Case 2 study, the most stringent I&M program was selected; i.e., quarterly monitoring, a 500 ppm leak definition, and directed maintenance (Table 7.7.c). Table 7.7.d gives the estimated ranges of SARA compounds based on the fugitives calculated in Table 7.7.c. Refer to section 5.5.2.3 for a discussion of the SARA constituents.

7.5.1.3 Benzene NESHAP Emissions

The TAB estimate for Case 2 is identical to Case 1. This is summarized in Table 6.8 of the preceding section, which shows a TAB of 0.00329 metric tons per year.

This reduction was accomplished by instituting the following methods and designs:

- A steam stripper was added to the desalter effluent line. Benzene and other VOC's are stripped and recycled to the process. The stripper effluent contains 0.005 ppmw of benzene.

- Installation of totally enclosed loops and totally enclosed sampling ports, which eliminate this source of emissions.

- All level bridles and vessel drains are drained to an MDO system, which recycles all crude, products, and intermediates, and eliminates all emissions.

7.5.1.4 VOC Emissions

Although hydrocarbon drains are prevented from entering the sewers, the sewers should be reconstructed to the VOC standards in NSPS Subpart QQQ. Even in a tightly-controlled environment, provisions for spills and accidents must be made. Adoption of the VOC standards will give protection in the event of a spill of hydrocarbons, and will give protection in the event of fire. Furthermore, NSPS standards will apply to reconstructed units.

7.5.2 Stormwater and Wastewater

7.5.2.1 Stormwater

No improvements to the stormwater management system were included in Case 2. It should be noted that the new NPDES stormwater regulations will probably require some modifications to the existing 1980s vintage storm sewer system.

7.5.2.2 Wastewater

In the revamped unit, the wastewater continues to be treated in the existing central WWTP. The revamped operation, however, virtually eliminates benzene discharge into the wastewater treatment facility. In addition, most hydrocarbons will be recycled to the process before entering the sewer.

To control VOC emissions resulting from spills, accidents, and fires, the sewer system was modified to meet VOC standards in NSPS Subpart QQQ. Since benzene is removed at-source, NESHAP Subpart FF standards are not applicable to this case.

The refinery WWTP itself will require VOC controls on the API separator, but otherwise will be essentially unchanged from the existing 1980s type treatment plant. The DAF unit in the refinery wastewater treatment plant will not require VOC controls to meet NSPS Subpart QQQ standards.

Table 7.8 summarizes the source of all wastewater produced by the revamped unit. The total flow of wastewater was reduced to 342 gpm. The quality of the water is also improved (by comparison with the Base Case) since the discharge contains only permissible amounts of benzene and VOCs, and a reduced content of O&G and TSS. Reducing the benzene and VOC content also results in a reduction in BOD, phenols, and sulfides, although this is a side effect of the at-source reduction process rather than an intended end result.

The suspended solids produced by chemical reactions between the wastewaters, water plant sludge, cooling tower blowdown, boiler water sludge, and boiler blowdown are eliminated by routing these wastewaters to a water recycle plant. The solids from the water recycle plant are treated separately and do not become part of the API sludge. Oil and grease from sample drains, instrument drains, and vessel drains are eliminated from the process sewer by re-routing to the MDO system.

The flow and O&G values for the desalter are taken from the design information as in the Base Case. The boiler blowdown, steam condensate loss, cooling tower blowdown, water plant sludge, and boiler water treatment plant discharge rates to the process sewer were estimated using the same techniques and basis as used in the Base Case. The water recycle plant sludge generation rate was estimated at 5% of the influent flow, with a concentration of 5% solids.

The entire 172 gpm of stripped sour water from the crude unit is reused in the desalter; thus, sour water is shown as both a credit and debit on the inventory.

The desalter is still the major contributor of process wastewater within the crude unit. This wastewater is contaminated with solids, phenols, COD, NH_3, and sulfides.

7.5.3 Solid and Hazardous Wastes

In order to minimize the production of RCRA listed wastes, the water plant sludge, boiler blowdown, boiler feed water treatment effluent, cooling tower blowdown, steam condensate drains, and all other wastewaters with low level TOC contamination are collected by a separate drain system and treated in a separate water recycle facility designed especially for this purpose. This facility is a physical-chemical treatment plant comprising a solids contact clarifier with sludge thickening and drying. This operation significantly reduces the volume of wastewater that must be treated in the wastewater treatment plant.

Estimates of the solid and hazardous wastes, except for K050, and other maintenance wastes, are presented in Table 7.9. The water treatment sludges and SO_x scrubber wastes no longer contribute to the generation of RCRA listed wastes since they are not allowed to enter the oily water sewer. Removal of the water treatment sludges in a separate facility significantly reduces the amount of RCRA wastes generated. The water treatment sludges and SO_x scrubber wastes may still be classified as hazardous, however, if they exhibit a characteristic.

7.6 Cost Estimate

The same cost estimate basis, qualifications, exclusions, and methodology used in the Base Case and in Case 1 apply to Case 2. The difference is that the overall design approach is oriented toward revamping an existing crude and vacuum unit (built in the early 1980s) to incorporate practicable pollution prevention ideas. The cost estimating approach remains the same, and only new and revamped equipment were accounted for in Case 2 (refer to Appendix G for equipment list).

The cost estimate for Case 2 totals $28,694,000.

7.7 Comparison with Base Case

7.7.1 Emissions and Effluents Reductions

Significant reductions in emissions and effluents were achieved in Case 2 when compared with the Base Case. These reductions are outlined below:

- Fossil fuel energy usage was reduced while electricity consumption increased. Energy derived from fossil fuels decreased 9% from 948 MMBTU/hr to 865 MMBTU/hr. Electrical power usage increased 19% from 2670 KW to 3190 KW.

- NO_x emissions were reduced:
  - 70% from 597 tons/year to 179 tons/year for the fuel oil cases,
  - 59% from 415 tons/year to 170 tons/year for the fuel gas case.

- SO_x emissions were reduced:
  - 92% from 7027 tons/year to 584 tons/year for the 3.34% sulfur fuel oil case,

  - 92% from 2105 tons/year to 176 tons/year for the 1.00% sulfur fuel oil case,
  - 91% from 423 tons/year to 37 tons/year for the 0.20% sulfur fuel oil case,
  - 9% from 3.3 tons/year to 3.0 tons/year for the fuel gas case.

- VOC emissions were reduced:
  - 91% from 190 tons/year to 18 tons/year for fuel oil,
  - 93% from 183 tons/year to 12 tons/year for fuel gas.

- CO emissions were reduced:
  - 9% from 171 tons/year to 156 tons/year for fuel oil,
  - 9% from 185 tons/year to 168 tons/year for fuel gas.

- TSP emissions were reduced:
  - 17% from 501 tons/year to 417 tons/year for the 3.34% sulfur fuel oil case,
  - 16% from 187 tons/year to 157 tons/year for the 1.00% sulfur fuel oil case,
  - 15% from 80 tons/year to 68 tons/year for the 0.20% sulfur fuel oil case,
  - 9% from 23 tons/year to 21 tons/year for the fuel gas case.

- Fugitive VOC emissions from piping components were reduced 97% from 176 tons/year to 6 tons/year, assuming a stringent I&M program (the actual reduction for a specific crude unit will depend on the control efficiency associated with the I&M program implemented).

- The total annual benzene quantity was reduced 99% from 28 Mg/yr to 0.00329 Mg/yr.

- Wastewater generation was reduced 41% from 584 gpm to 342 gpm by process modifications, reduction in energy usage, and recycling.

- RCRA hazardous wastes were reduced 93% from 12,535 ppd to 934 ppd. Non-hazardous solid waste generation increased from 0 ppd for the Base Case to between 7472 ppd and 84,767 ppd, depending on the fuel case.

7.7.2 Technology and Methods for Pollution Reductions

To achieve the above reductions in environmental emissions from the plant, the design features described below were reflected in the process flow diagrams, the major equipment list, and the cost estimate for Case 2.

To utilize the existing crude-preheat train to its fullest potential, three new exchangers were added to raise the preheat temperature by 50 °F. The added surface amounts to 8% additional area as compared to Base Case. Some exchanger flow sequences were rearranged in order to optimize the crude preheat recovery. Piping bypasses at several locations were also installed in order to accommodate the revised exchanger sequences.

New sidestrippers were added to provide space for the additional trays required when converting to reboiled strippers. As in Case 1, a hot oil heater was installed to provide heat input to the three reboiled side-strippers.

7.8 Cost/Benefit Analysis of Environmental Upgrades

The costs and benefits of each environmental upgrade (method, device, or procedure) employed in Case 2 are summarized in Table 7.10. The costs are not limited to monetary costs. For instance, costs include non-monetary restraints such as reduced operational flexibility, increased maintenance and reporting requirements, and increased training requirements, etc. In the same manner, benefits include monetary and non-monetary items. Monetary benefits include reduced energy requirements and lower worker health-care costs. Non-monetary benefits include reduced emissions, increased safety, increased process knowledge, and decreased worker exposure to toxic or hazardous materials.

Table 7.10 should not be considered a complete cost benefit analysis, but rather an attempt to measure and list all direct, known, and tangible benefits that accrue to the refinery. Indirect benefits such as reduced exposure of the populace to various pollutants and increased public health are not quantified as the measurement of their impact is beyond the scope of the study.

While the Base Case crude unit was built in the early 1980s, most refinery crude units are considerably older. It can be generalized that the cost of retrofitting older crude units will be higher than the estimates presented here for retrofitting the Base Case crude unit.

7.8.1 Cost Analysis of Pollution Abatements

Table 7.10 identifies the annualized cost of NO_x, VOC, and SO_x removal per ton of net emissions reduction.

The annualized cost for NO_x net emission reduction refers to the total installed cost of the SCR unit required to further reduce NO_x emissions by 90% from the low-NO_x burners provided with the furnaces.

The annualized cost for VOC net emission reduction refers only to the costs for selected pump seal replacement, upgraded valves/flanges, MDO system, and benzene removal stripper.

SO_x emission control will not be required while burning fuel gas because of low emission levels. However, for burning fuel oil the SO_x levels can be reduced 90% with a limestone scrubber.

To conserve energy, heat exchangers can be added to the crude and vacuum unit, and their payout is detailed in Table 7.11. Net emissions reduction can be achieved at no cost as a by-product of energy conservation.

7.9 Summary and Conclusions

The total fossil fuel energy use for Case 2 is 864.5 MMBTU/hr, and the electricity usage is 3190 KW with the SO_x scrubber and 3033 KW without the scrubber.

Case 2 air emissions are summarized in Table 7.12. SO_x and TSP emissions increase proportionally with increasing sulfur content of the fuel. Burning fuel oil increases NO_x emissions compared to burning fuel gas.

Table 7.12 includes 5.8 tons/year of fugitive VOC emissions for each fuel case.

The total annual benzene quantity for the Case 2 crude unit is 0.00329 metric tons/year.

Total wastewater flow produced by the crude unit is 342 gpm. The wastewater contains 119 gals/day of O&G, 7472 lbs/day of TSS, 4571 lbs/day of COD, 572 lbs/day of NH_3, 131 lbs/day of sulfides, and 199 lbs/day of phenols.

Between 7472 ppd and 84,767 ppd of non-hazardous solid waste are produced depending on fuel. The least amount of non-hazardous solid waste is produced by burning fuel gas, and the most by burning 3.34% sulfur fuel oil. A total of 934 lbs per day of RCRA solid hazardous wastes are produced.

TABLE 7.1
CASE 2
CHEMICAL REQUIREMENTS

User Chemical	Chemical Requirements		
Desalter Water			
Sulfuric Acid	6.0	GPH	
Crude Charge			
Caustic (31°Be)	0.5	GPH	
Crude Tower			
Ammonia	10.0	LBS/HR	
Corrosion inhibitors	0.7	GPH	
Vacuum Tower			
Ammonia	3.0	LBS/HR	
NO_x SCR			
Ammonia (theoretical)	25.69	LBS/HR	
Catalyst	1,000	ft3/yr	
Wet Limestone Scrubber (fuel oil firing in B-101 only)			
CaCO3 (theoretical)	1,871	LBS/HR	3.34wt%S
CaCO3 (theoretical)	560	LBS/HR	1.0 wt%S
CaCO3 (theoretical)	112	LBS/HR	0.2 wt%S
Zero Discharge - Cooling Tower			
Sodium Molybdates	0.01-0.06	GPH	
Dispersant	0.15	GPH	
Biocide	0.5-0.7	LBS/HR	
Chlorine	50-70	LBS/HR	
Sulfuric Acid	3-8	LBS/HR	

TABLE 7.2

CASE 2
UTILITY REQUIREMENTS

Utility	Requirements	
Cooling Water Circulation	27,104	GPM
Electricity Consumption	3,190	KW
Fossil Fuel Energy	864.5	MMBTU/hr
Steam		
500# Consumption	120,010	LBS/HR
Production	120,010	LBS/HR (1)
125# Consumption	120,884	LBS/HR
Production	53,240	LBS/HR
50# Consumption	39,500	LBS/HR
Production	11,784	LBS/HR
15# Consumption	10,000	LBS/HR
Production	69,710	LBS/HR

(1) From steam boilers in utility area.

TABLE 7.3

CASE 2
AIR EMISSIONS
(FUEL GAS CASE)

EMISSION SOURCE	DESCRIPTION	HEAT RELEASE (MMBTU/HR)	AIR EMISSIONS (Tons/Year) NO_x	CO	VOC	TSP	SO_2
FUEL GAS							
B-102	Vacuum Heater	149.5	3.93	29.10	1.02	3.64	0.52
OSBL	Boilers	340	148.92	66.19	2.32	8.27	1.18
B-103	Hot Oil System	30	7.88	5.11	0.41	0.73	0.10
B-101	Atmospheric Heater	345	9.07	67.16	2.35	8.40	1.20
	Total Energy	864.50					
	ANNUAL STACK EMISSIONS		169.80	167.56	6.09	21.04	3.01
	ANNUAL FUGITIVE EMISSIONS (from Table 7.7.c)		0	0	5.79	0	0
	TOTAL ANNUAL AIR EMISSIONS		169.80	167.56	11.88	21.04	584.45

TABLE 7.4

CASE 2
AIR EMISSIONS
(0.2% FUEL OIL CASE)

EMISSION SOURCE	DESCRIPTION	HEAT RELEASE (MMBTU/HR)	AIR EMISSIONS (Tons/Year)				
			NO_x	CO	VOC	TSP	SO_2
FUEL GAS							
B-102	Vacuum Heater	149.5	3.93	29.10	1.02	3.64	0.52
OSBL	Boilers	340	148.92	66.19	2.32	8.27	1.18
B-103	Hot Oil System	30	7.88	5.11	0.41	0.73	0.10
FUEL OIL							
B-101	Atmospheric Heater	345	18.13	55.56	8.44	55.56	34.89
	Total Energy	864.50					
	ANNUAL STACK EMISSIONS		178.87	155.95	12.19	68.20	36.69
	ANNUAL FUGITIVE EMISSIONS (from Table 7.7.c)		0	0	5.79	0	0
	TOTAL ANNUAL AIR EMISSIONS		178.87	155.95	17.98	68.20	36.69

TABLE 7.5

CASE 2
AIR EMISSIONS
(1.0% FUEL OIL CASE)

EMISSION SOURCE	DESCRIPTION	HEAT RELEASE (MMBTU/HR)	AIR EMISSIONS (Tons/Year)				
			NO_x	CO	VOC	TSP	SO_2
FUEL GAS							
B-102	Vacuum Heater	149.5	3.93	29.10	1.02	3.64	0.52
OSBL	Boilers	340	148.92	66.19	2.32	8.27	1.18
B-103	Hot Oil System	30	7.88	5.11	0.41	0.73	0.10
FUEL OIL							
B-101	Atmospheric Heater	345	18.13	55.56	8.44	144.44	174.44
	Total Energy	864.50					
	ANNUAL STACK EMISSIONS		178.87	155.95	12.19	157.08	176.25
	ANNUAL FUGITIVE EMISSIONS (from Table 7.7.c)		0	0	5.79	0	0
	TOTAL ANNUAL AIR EMISSIONS		178.87	155.95	17.98	157.08	176.25

TABLE 7.6

CASE 2
AIR EMISSIONS
(3.34% FUEL OIL CASE)

EMISSION SOURCE	DESCRIPTION	HEAT RELEASE (MMBTU/HR)	AIR EMISSIONS (Tons/Year)				
			NO_x	CO	VOC	TSP	SO_2
FUEL GAS							
B-102	Vacuum Heater	149.5	3.93	29.10	1.02	3.64	0.52
OSBL	Boilers	340	148.92	66.19	2.32	8.27	1.18
B-103	Hot Oil System	30	7.88	5.11	0.41	0.73	0.10
FUEL OIL							
B-101	Atmospheric Heater	345	18.13	55.56	8.44	404.44	582.64
	Total Energy	864.50					
	ANNUAL STACK EMISSIONS		178.87	155.95	12.19	417.08	584.45
	ANNUAL FUGITIVE EMISSIONS (from Table 7.7.c)		0	0	5.79	0	0
	TOTAL ANNUAL AIR EMISSIONS		178.87	155.95	17.98	417.08	584.45

TABLE 7.7.a

CASE 2
FUGITIVE VOC EMISSIONS CALCULATIONS

SOURCE	STREAM COMPOSITION	NUMBER OF SOURCES	AP-42 EMISSION FACTOR (LB/HR/SOURCE)	CONTROL METHOD	CONTROL EFFICIENCY %	CONTROLLED EMISSIONS (LB/HR)	CONTROLLED EMISSIONS (TON/YR)
Valves	gas	272	0.059	note 1	75	4.012	17.573
	light liquid	199	0.024	note 1	75	1.194	5.230
	heavy liquid	1331	0.0005	note 1	75	0.166	0.729
Pump Seals	light liquid	10	0.25	note 1	75	0.625	2.738
	heavy liquid	32	0.046	note 1	75	0.368	1.612
Flanges	gas	347	0.00056	note 2	30	0.136	0.596
	light liquid	283	0.00056	note 2	30	0.111	0.486
	heavy liquid	2452	0.00056	note 2	30	0.961	4.210
Open-Ended Valves		489	0.005	note 3	100	0.000	0.000
Relief Valves		37	0.36	note 4	100	0.000	0.000
Compressor Seals		3	1.4	note 5	100	0.000	0.000
Drains		126	0.07	note 6	100	0.000	0.000
Sample Connections		24	none	note 7	100	0.000	0.000
			TOTAL FUGITIVE EMISSIONS			7.574	33.172

NOTES:

1. Quarterly monitoring, 10,000 ppm leak definition, non-directed maintenance.
2. Weekly physical inspection (visual, audible, or olfactory).
3. Plug, blind, or cap open end.
4. Discharge to flare.
5. Recycle to process, double seal shafts, and vent crankcase to flare.
6. Hard pipe to Maintenance Drain Out System.
7. Closed loop sampling.

TABLE 7.7.b

CASE 2
FUGITIVE VOC EMISSIONS CALCULATIONS

SOURCE	STREAM COMPOSITION	NUMBER OF SOURCES	AP-42 EMISSION FACTOR (LB/HR/SOURCE)	CONTROL METHOD	CONTROL EFFICIENCY %	CONTROLLED EMISSIONS (LB/HR)	CONTROLLED EMISSIONS (TON/YR)
Valves	gas	272	0.059	note 1	90	1.605	72.029
	light liquid	199	0.024	note 1	90	0.478	2.092
	heavy liquid	1331	0.0005	note 1	90	0.067	0.291
Pump Seals	light liquid	10	0.25	note 1	90	0.250	1.095
	heavy liquid	32	0.046	note 1	90	0.147	0.645
Flanges	gas	347	0.00056	note 2	30	0.136	0.596
	light liquid	283	0.00056	note 2	30	0.111	0.486
	heavy liquid	2452	0.00056	note 2	30	0.961	4.210
Open-Ended Valves		489	0.005	note 3	100	0.000	0.000
Relief Valves		37	0.36	note 4	100	0.000	0.000
Compressor Seals		3	1.4	note 5	100	0.000	0.000
Drains		126	0.07	note 6	100	0.000	0.000
Sample Connections		24	none	note 7	100	0.000	0.000
			TOTAL FUGITIVE EMISSIONS			3.754	16.444

NOTES:

1. Quarterly monitoring, 10,000 ppm leak definition, directed maintenance.
2. Weekly physical inspection (visual, audible, or olfactory).
3. Plug, blind, or cap open end.
4. Discharge to flare.
5. Recycle to process, double seal shafts, and vent crankcase to flare.
6. Hard pipe to Maintenance Drain Out System.
7. Closed loop sampling.

TABLE 7.7.d

CASE 2
SARA CONSTITUENTS IN FUGITIVE VOC EMISSIONS

		WEIGHT PERCENT OF TOTAL			
SARA COMPOUND	LIGHT LIQUID SERVICE	VAPOR SERVICE	CRUDE OIL SERVICE	EXAMPLE ASSAY OF ARABIAN LIGHT	ESTIMATED LBS/YEAR
Benzene	0.2 - 2.0 %	0.0 - 0.5 %	0.0 - 0.5 %	0.12 %	3 - 36
Toluene	0.5 - 5.0 %	0.0 - 0.5 %	0.0 - 1.0 %	0.64 %	8 - 82
Ethylbenzene	0.2 - 2.0 %	0.0 - 0.5 %	0.0 - 0.5 %	0.39 %	3 - 36
Xylene	0.5 - 5.0 %	0.2 - 1.5 %	0.0 - 1.5 %	1.03 %	10 - 91
Cyclohexane	0.5 - 2.0 %	0.0 - 0.5 %	0.0 - 1.0 %	0.26 %	8 - 36

TABLE 7.7.c

CASE 2
FUGITIVE VOC EMISSIONS CALCULATIONS

SOURCE	STREAM COMPOSITION	NUMBER OF SOURCES	AP-42 EMISSION FACTOR (LB/HR/SOURCE)	CONTROL METHOD	CONTROL EFFICIENCY %	CONTROLLED EMISSIONS (LB/HR)	CONTROLLED EMISSIONS (TON/YR)
Valves	gas	272	0.00031	note 1	0	0.084	0.369
	light liquid	199	0.00062	note 1	0	0.123	0.540
	heavy liquid	1331	0.00051	note 1	0	0.679	2.973
Pump Seals	light liquid	10	0.00437	note 1	0	0.044	0.191
	heavy liquid	32	0.00838	note 1	0	0.268	1.175
Flanges	gas	347	0.00004	note 2	0	0.014	0.061
	light liquid	283	0.00004	note 2	0	0.011	0.050
	heavy liquid	2452	0.00004	note 2	0	0.098	0.430
Open-Ended Valves		489	0.00029	note 3	100	0.000	0.000
Relief Valves		37	0.02514	note 4	100	0.000	0.000
Compressor Seals		3	0.02496	note 5	100	0.000	0.000
Drains		126	none	note 6	100	0.000	0.000
Sample Connections		24	none	note 7	100	0.000	0.000
			TOTAL FUGITIVE EMISSIONS			1.322	5.789

NOTES:

1. Quarterly monitoring, 500 ppm leak definition, directed maintenance.
2. Quarterly monitoring, 500 ppm leak definition, directed maintenance, but may consider using AP-42 factor with 30% control for weekly physical inspection (visual, audible, or olfactory).
3. Plug, blind, or cap open end.
4. Discharge to flare.
5. Recycle to process, double seal shafts, and vent crankcase to flare.
6. Hard pipe to Maintenance Drain Out System.
7. Closed loop sampling.

TABLE 7.8

CASE 2
WASTEWATER INVENTORY

		POLLUTANT CONCENTRATIONS (PPMW)							MASS FLOW (LBS/DAY EXCEPT O&G IN GALS/DAY)						
SOURCE	FLOW GPM	OIL & GREASE	TSS	BOD	COD	NH_3	SULFIDES	PHENOL	OIL & GREASE	TSS	BOD	COD	NH_3	SULFIDES	PHENOL
DESALTER EFFLUENT	331	250	150		1150	144	33	50	119.16	596.28		4571.45	572.43	131.18	198.76
SAMPLING DRAINS	0								0						
INSTRUMENTS	0								0						
VESSEL DRAINS	0								0						
WATER RECYCLE PLANT SLUDGE	11.45		5000				0	0		6875.78					
SOUR WATER TO SOUR WATER STRIPPER	172														
STRIPPER SOUR WATER TO DESALTER	-172														
TOTALS	342.45								119.16	7471.78		4571.45	572.43	131.18	198.76

TABLE 7.9

CASE 2
INVENTORY OF SOLID AND HAZARDOUS WASTE PRODUCTION

Waste	Quantity (tons/day)
Hazardous Wastes (Note 1)	0.5
Non-Hazardous Wastes	
Sludge (except SOx Scrubber Sludge)	3.7
SOx Scrubber Sludge	
Fuel Gas	0
0.2% Sulfur Fuel Oil	2.3
1.0% Sulfur Fuel Oil	11.6
3.34% Sulfur Fuel Oil	38.6

Note 1: Does not include K050 or other maintenance wastes.

TABLE 7.10

CASE 2
NET EMISSION REDUCTION ANNUALIZED COST ANALYSIS

Case 2	NO_x	VOC	SO_2
net emission reduction, t/y			
fuel gas	117	170	n/a
fuel oil 1 wt % S	199	170	1,570
annualized cost, $/ton			
fuel gas	28,228	5,444	n/a
fuel oil 1 wt % S	19,366	5,444	1,562

TABLE 7.11

CASE 2
HEAT INTEGRATION OF CRUDE PREHEAT

Cost:

	Additional * Exchangers Total Installed Cost
Crude Preheat Exchangers	$ 2,268,000

Fuel Savings

	Duty, MMBTU/Hr	Cost $/Yr
Base Case	415.9	$ 9,894,000
Case 1	344.8	$ 8,202,000
Delta (Base Case - Case 1)	91.1	$ 1,692,000

Payout = Cost/Savings
$ 2,268,000 / $1,692,000 / Yr.
= 1.34 Yrs.

*** Added C-302, C-209 and C-309**

TABLE 7.12

CASE 2
SUMMARY OF AIR EMISSIONS

(Tons/year)

FUEL	NO_x	CO	VOC	TSP	SO_x
Fuel Gas	170	168	12	21	3.0
Fuel Oil					
0.2% Sulfur	179	156	18	68	37
1.0% Sulfur	179	156	18	157	176
3.34% Sulfur	179	156	18	417	584

APPENDIX A:

Summary of Pollution Prevention Ideas:

Brainstorm List

I. PROCESS MODIFICATIONS

	Idea	Explanatory Comment	Affected Medium				Environmental Benefits	Cost Impacts
			A	WW	SW	HW		
1.	Waterless desalters, crude pretreatment & "guard" bedding	Reserve osmosis/desiccant. Emerging Technology.	x	x		x	high	high
2.	Use flue gas instead of steam for stripping crude tower	Minimize steam use in crude tower	x	x	x		low	high
*	Flue Gas Recirculation (FGR) for NO_x Control	Recirculate flue gas as combustion air to lower flame temperature.	x				high	medium
3.	Gas chromatographic separation for C_4 & Heavier	Prototype technology for product separation.	x	x		x	medium	high
4.	Heat Transfer Systems							
*	- Non-water	Hot oil system instead of steam.	x	x	x		high	medium
	- Air coolers	Air coolers instead of cooling water exchangers.	x	x	x		high	high
	- Closed system (not necessarily water)	Synthetic oil, salt, sodium,etc. instead of steam system.	x	x	x		high	high
5.	Strainer cleaning & back flushing	Recirculated to closed system to minimize water use and hazardous/solid waste generation.			x	x	low	low
6.	Consider routing all relief valves and pump seal vents on preheat train into crude tower flash zone.	Recover hydrocarbons. Safety concern. Requires complex piping arrangement.	x	x		x	low	medium

	Idea	Explanatory Comment	Affected Medium				Environmental Benefits	Cost Impacts
			A	WW	SW	HW		
7.	Desalting							
	- Use unstripped sour water from crude & vacuum tower for desalting	Smaller sour water stripper.	x	x			medium	low
8.	Two stage desalting							
*	- Two stage desalting	Reduce salt < 1 lb. per 1000 bbl.	x	x	x		high	high
	- Preheat desalter wash water	Heat conservation.	x	x	x		high	high
9.	Preflash Unit							
	- Install preflash unit to minimize energy (lower preheat operating pressure)	Remove light material ahead of crude furnace.	x				medium	medium
10.*	Excess Combustion Air Control	Require CO/O_2 analyzers and damper controls.	x				high	low
11.	Furnaces							
*	- Low NO_x burners with flue gas re-circulation	Good return on investment for NO_2 reduction.	x				medium	low
	- Upgrade metallurgy to prevent fouling	Reduces fired duty.	x				medium	high
	- Use lower polluting heat sources (nuclear, electric, etc.)	Emerging technology.	x				high	high
*	- Maximize flue gas heat recovery	Good return on investment.	x				high	medium
*	- Use sulfur free fuel gas	Reduce need for post combustion control.	x				high	low
	- Recover flue gas CO_2	As for Tertiary Oil Recovery.	x				high	high
	- Burn hydrogen fuel in furnaces	Relatively high cost.	x				medium	high

	Idea	Explanatory Comment	A	Affected Medium WW	SW	HW	Environmental Benefits	Cost Impacts
12.*	NO_x - SCR	Selective Catalytic Reduction (SCR): NO_x - > N_2 Commercially proven technology.	x				high	high
13.	Thermal De-NO_x							
*	- NH_3 injection	Less effective than SCR. Ammonia slippage problem.	x				high	high
	- Urea injection	Less effective than SCR. Ammonia slippage problem.	x				high	high
14.	Crude Column							
	- Consider fully packed column	High capital cost.		x	x	x	low	high
	- Overall energy efficiency of high vs. low flash zone pressure	Could generate off spec kerosene.	x				low	high
•	- Reboiled side strippers (may result in high chlorides levels in overheads - may require condensate addition)	Eliminate stripping steam to the side stripper.	x	x	x		high	high
	- Recover additional overhead wet gas by refrigerations or sponge oil to reduce compression energy	Relatively high cost. Small amount of recoverable hydrocarbon in overhead.		x			medium	high
•	- Optimize top pumparound duty in preference to reflux	Minimize cooling water usage.		x	x		medium	medium

	Idea	Explanatory Comment	Affected Medium				Environmental Benefits	Cost Impacts
			A	WW	SW	HW		
15.	Vacuum Unit							
	- Refrigerated top pumparound to reduce sour gas	Relatively high cost. This might help the case for using vacuum pumps to reduce energy.	x				medium	high
*	- Use packed column	Improved process performance.	x	x			high	medium
16.	Vapor recompression (heat pump cycle on crude tower overhead)	Not technically feasible for a crude distillation unit.	x				low	high
17.	Drainage							
	- water/oil sludge contained/integrated into sour water/desalter systems	Integrated environmental management program. Emerging technology.	x		x		high	medium
18.	Separation							
	- Eliminate vacuum distillation by combining with other processes - i.e., resid heavy oil cracking - long resid (crude tower bottoms)	Affects products specifications. Impacts on downstream process units.	x	x	x	x	high	high
	- Eliminate chemical treatment to reduce fouling (pH, corrosion control)		x	x	x	x	high	high

	Idea	Explanatory Comment	Affected Medium				Environmental Benefits	Cost Impacts
			A	WW	SW	HW		
	- Use membrane or solvent process to separate all or part of crude	Emerging technology.	x	x	x	x	high	high
	- Develop a "molecular centrifuge"	Emerging technology.	x	x	x	x	high	high
	- Optimize distillation pressure & temperature	Improve process efficiency.	x			x	medium	medium
	- Employ distributed distillation techniques	Under development.	x	x			high	medium
	- Recycle desalter water	Requires intermediate treatment.		x	x	x	high	high
	- Use ultra-high vacuum distillation to reduce energy input	Below 5 mmHg. Emerging technology.	x	x		x	high	high
19.	Develop engine/power plants which run on whole crude to reduce refinery throughout	Emerging technology.	x	x		x	low	high
20.	Delivery System							
	- Use double-bottom tanks with leak detection/monitor with sonar detection, etc.	Reduce risk and liability.		x		x	low	high
	- Direct blend to downstream shipping	Inline blending.	x			x	high	medium
	- Eliminate desalter, build crude unit to tolerate solids, water, NaCI, HCI...	High cost impacts.	x	x			high	high
	- Remove salt from desalter brine by refrigeration or RO-recycle water back to desalter	Relatively high cost.	x	x	x	x	high	high

	Idea	Explanatory Comment	Affected Medium				Environmental Benefits	Cost Impacts
			A	WW	SW	HW		
21.	Crude Tower - eliminate crude tower side strippers. Add trays to main fract - flash point corrections in downstream units	Impact product specifications.	x	x			low	high
22.	Have hydrocarbon recovery system on flare header	Recover flare gases as fuel.	x			x	high	medium
23.	Provide PCVs for small controlled releases to relief header	Controlled flaring for hydrocarbons.	x			x	high	low
24.	Increase design pressure to minimize releases	High capital costs.	x			x	high	high
25.	Use integral condensers and reboilers	Used in side strippers. Lowers operating pressure.	x			x	medium	low
26.	Simple flash drum after desalters	Lowers operating pressure. Removes light material ahead of crude furnace.	x	x		x	low	low

Abbreviations:

A = Air
WW = Wastewater
SW = Solid Waste
HW = Hazardous Waste

* Employed in study

II. PROCESS OPTIMIZATIONS

	Idea	Explanatory Comment	Affected Medium A	WW	SW	HW	Environmental Benefits	Cost Impacts
1.	Tankage							
	- Use floating suction & crude oil blending mixers (this to eliminate slugs of water & the need to draw BS&W from tank which is contaminated with benzene.	Commerically proven. Presently used by many refineries.	x	x		x	high	low
2.•	Feed Preheat/Feed-Effluent Exchanger	Pinch analysis/energy optimizations	x	x	x		high	medium
3.	Vacuum Ejectors							
* -	Discharge Vapor to fuel gas header	Recycle Waste Gases	x				high	low
* -	Dry (non-liquid systems)	No steam required	x	x			high	low
4.	Minimization of hydrocarbon losses during Start-Up and Shutdown							
-	Reduce flare load	Good engineering and operating practice.	x		x		high	low
* -	Maximum use of redundant instrumentation	Good engineering and operating practice.	x	x	x		high	medium
		Good engineering and operating practice.		x	x		high	medium
* -	"Who's in the flare" instrument	Good engineering and operating practice.	x				high	low
* -	"Who's in the sewer" instrument	Good engineering and operating practice.	x	x	x		medium	low
5.*	On-stream Analysis Integrated into Advanced Control Systems	Energy saving and process optimization.	x	x	x	x	high	medium
6.*	Computer Aided Procedure Verification for Startup and Shutdown							
	- Normal start-up and shutdown - Emergency shutdown	Advanced control. Advanced control.	x	x	x	x	high	medium

	Idea	Explanatory Comment	Affected Medium				Environmental Benefits	Cost Impacts
			A	WW	SW	HW		
7.	Preheat Train Design for high tube side velocities, get lower fouling - metallurgy upgraded to cope with erosion	Material cost impacts.			x	x	medium	high
8.	General							
	- Use variable speed pumps to reduce energy use	Eliminate control valves.	x				medium	high
9.*	Chloride control in overhead by:							
	- Wash Water	Good engineering practice.	x	x	x	x	medium	medium
	- Corrosion Inhibitors	Good engineering practice.	x	x	x	x	medium	medium
10.*	Better crude tower control	Advanced control	x	x	x	x	medium	medium
11.	Furnance							
	- Combine all heaters into one.	Not practical and services are not centrally located.	x				low	high
*	- Hot oil system							
12.	Electrically heated hot oil system	Only small sizes are available.	x	x			medium	medium
13.	Heat Exchangers							
*	- Maximize heat integration	Apply pinch analysis.	x	x	x	x	high	medium
	- Design to eliminate fouling (velocities, self-cleaning).	In practice to some degree.	x	x	x	x	low	high
	- Construct of "non-stick" non-corrosive material.							
	- Design with a "spare" to allow change on the run.							
	- Online exchanger cleaning							
14.	Feed							
	- Do not accept crude oil with high BS&W	Not practical.	x	x	x	x	high	high
	- Do not accept spiked crude with high vapor pressure.	Not practical.	x	x	x	x	high	high
	- Keep solids suspended until you want them to settle out, in the asphalt, for example.	Install mixer in charge tank.		x	x	x	high	low
	- Refrigerate whole crude to minimize vapor pressure.	Not practical.	x			x	high	low

	Idea	Explanatory Comment	Affected Medium A	Affected Medium WW	Affected Medium SW	Affected Medium HW	Environmental Benefits	Cost Impacts
15.	Generic							
	- Utilize in-line inspection technology analyzer	Use "smart-pig", port holes, or sonar to allow maintenance/inspection without opening equipment.	x	x	x	x	low	medium
	- Develop a cleaning solvent or other mechanism to clean the system without opening up	Disposal problems.	x	x	x	x	low	medium
	- Utilize "Expert" computer systems to anticipate/deal with upsets	Advanced process control.	x	x	x	x	high	medium
16.	Train operations, process engineers, etc., to ensure operations are optimized.	Operating procedures.	x	x	x	x	high	low
17.*	Use non-chrome treating in cooling towers	Molybdenum Salt (Sodium Molybdate) or Phosphate.			x	x	high	low
18.	Delivery System							
	- Level alarms & auto shutoffs to prevent overfilling tanks	Install high-level alarm.	x	x		x	high	low
	- Minimize pumping, gravity feed	Site specific.	x	x		x	medium	high
*	- Send hot feed directly to downstream plants	Eliminate intermediate cooling.	x	x			high	low
19.	Air Coolers	Maximize air cooling; use dry cooling tower.	x	x	x		medium	high

Abbreviations:

A = Air
WW = Wastewater
SW = Solid Waste
HW = Hazardous Waste

* Employed in study

III. SOURCE TREATMENT

	Idea	Explanatory Comment	Affected Medium A	WW	SW	HW	Environmental Benefits	Cost Impacts
1.	Centrifugal Separator Applications (e.g., Hydrocyclone for de-oiling brine waste from desalter)	Emerging technology.		x	x		low	high
2.	Desalting	Fractionation.	x	x	x	x	high	medium
* -	Steam strip desalter brine to remove BTX.		x	x	x	x	high	high
* -	Brine De-Oiling/Brine Oxidation							
3.	Minimize sour water from vacuum tower							
* -	Dry tower	No stripping steam.	x	x			high	medium
* -	Vacuum pumps	Reduce motive steam.	x	x			high	medium

Abbreviations:

A = Air
WW = Wastewater
SW = Solid Waste
HW = Hazardous Waste

* Employed in study

IV. WASTE SEGREGATION

	Idea	Explanatory Comment	Affected Medium				Environmental Benefits	Cost Impacts
			A	WW	SW	HW		
1.*	Sewer Design							
	- Above-grade sewers	Reduce liabilities.				x	high	low
	- Segregated sewers	Good return on investment. Costly to implement in old refineries.				x	high	low

Abbreviations:

A = Air
WW = Wastewater
SW = Solid Waste
HW = Hazardous Waste

* Employed in study

V. END-OF-THE-PIPE TREATMENT

	Idea	Explanatory Comment	Affected Medium A	Affected Medium WW	Affected Medium SW	Affected Medium HW	Environmental Benefits	Cost Impacts
1.*	Biological Treatment	Enhanced above ground biotreatment.		x		x	high	medium
2.	Send all sludges to coker	Acceptable practice by many refineries. EPA approval required.			x	x	high	low

Abbreviations:

A = Air
WW = Wastewater
SW = Solid Waste
HW = Hazardous Waste

- Employed in study

VI. FUGITIVE EMISSION MANAGEMENT

	Idea	Explanatory Comment		Affected Medium			Environmental Benefits	Cost Impacts
			A	WW	SW	HW		
1.*	Fugitive Emission Management							
	- All welded connections	Zero fugitives. Applicable to small size piping system.	x			x	low	medium
	- Monitors and maintenance	Reduce fugitive emission.	x			x	medium	medium
	- Leakless valves	Economically feasible for small size valves.	x			x	medium	high
	- Quality assurance program for mechanical equipment suppliers	Good return on investment.	x	x	x	x	high	low
	- Seal-less pump/magnetic drive							
2.*	Vapor controls on sewer vents	Required for Benzene NESHAP collection sewers.	x			x	medium	medium
3.	Crude Tankage							
	- Vapor vents floating roof vs. fixed roof with vapor recovery	VOC/Benzene NESHAP compliance.	x			x	high	medium
4.	Sampling							
*	- Use closed sampling system	Good engineering practice.	x	x		x	high	low
*	- Utilize in-line analyzers	Good engineering practice.	x	x		x	high	high

Abbreviations:

A = Air
WW = Wastewater
SW = Solid Waste
HW = Hazardous Waste

* Employed in study

VII. CONTAINMENT

	Idea	Explanatory Comment	A	Affected Medium WW	SW	HW	Environmental Benefits	Cost Impacts
1.	Pile Sealing	Prevent underground contamination.		x		x	low	low
2.	Generic - Underground piping should have adequate surface coating to guard against corrosion. Double walled pipe with leak detection monitoring	Good engineering practice. Double wall pipe with hydrocarbon or lead detection monitoring is gaining popularity in hazardous waste facilities.	x		x		high	high
3.*	Liners and leachate collection	Eliminate ground water contamination.		x	x	x	high	medium

Abbreviations:

A = Air
WW = Wastewater
SW = Solid Waste
HW = Hazardous Waste

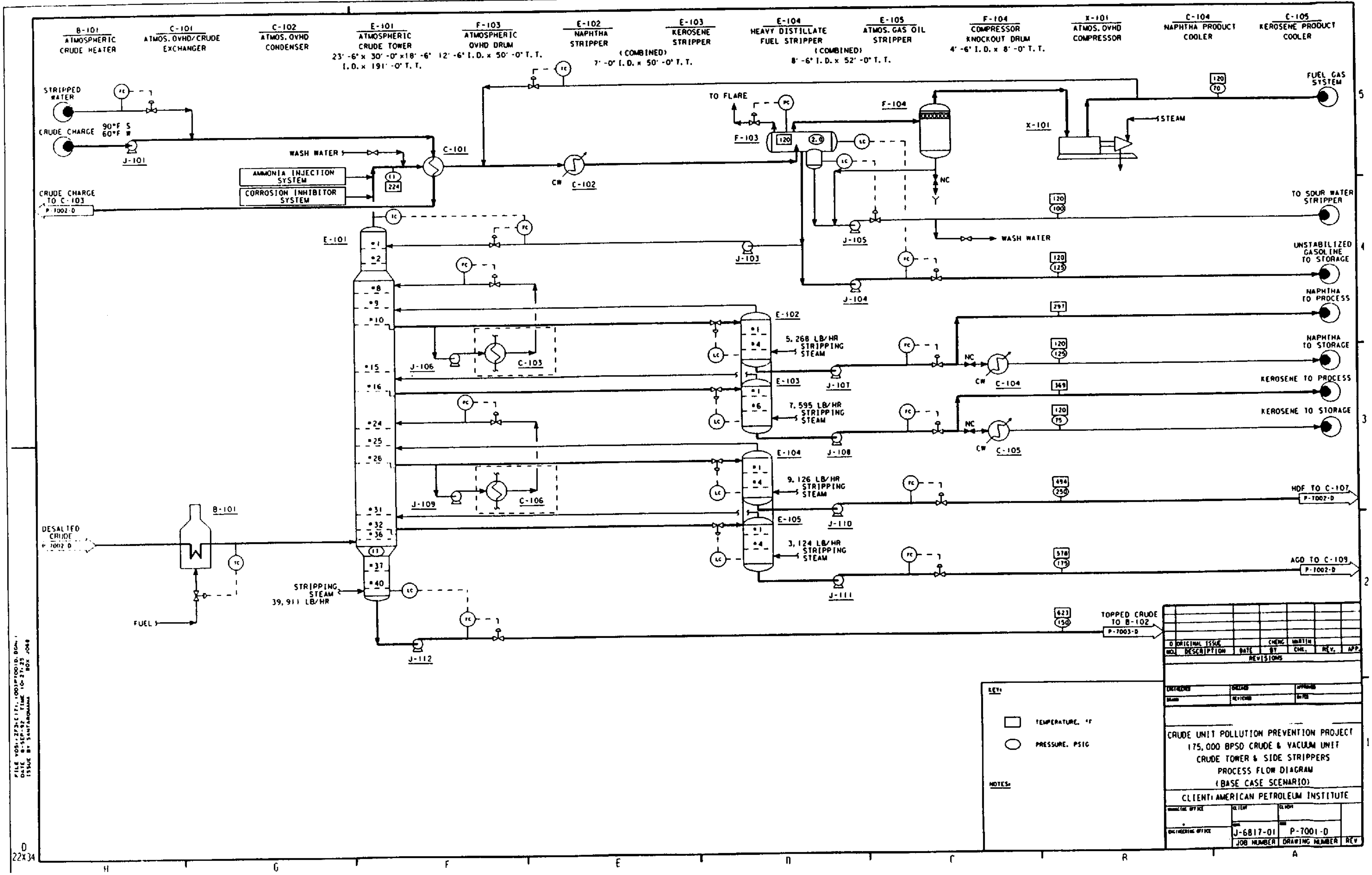
* Employed in study

APPENDIX B:

Process Flow Diagrams

for

Base Case



KEY:

▭	TEMPERATURE, °F
⬭	PRESSURE, PSIG

NOTES:

NO.	DESCRIPTION	DATE	BY	CHK.	REV.	APP.
0	ORIGINAL ISSUE		CHENG	MARTIN		

REVISIONS

CRUDE UNIT POLLUTION PREVENTION PROJECT
175,000 BPSD CRUDE & VACUUM UNIT
CRUDE TOWER & SIDE STRIPPERS
PROCESS FLOW DIAGRAM
(BASE CASE SCENARIO)

CLIENT: AMERICAN PETROLEUM INSTITUTE

JOB NUMBER	DRAWING NUMBER	REV
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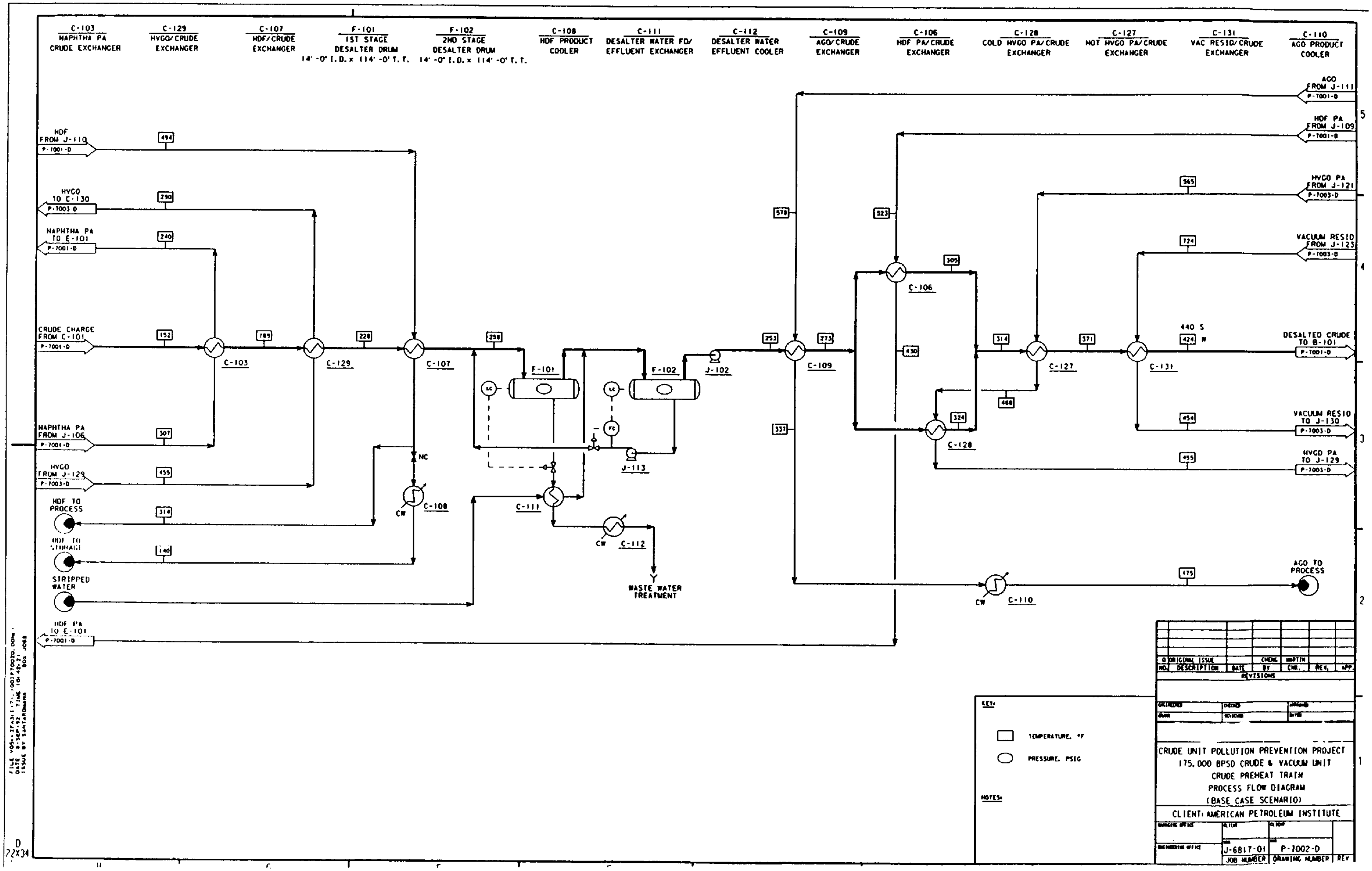

KEY:

- □ TEMPERATURE, °F
- ○ PRESSURE, PSIG

NOTES:

NO.	DESCRIPTION	DATE	BY	CHK.	REV.	APP.
0	ORIGINAL ISSUE		CHENG	MARTIN		

REVISIONS

CRUDE UNIT POLLUTION PREVENTION PROJECT
175,000 BPSD CRUDE & VACUUM UNIT
CRUDE PREHEAT TRAIN
PROCESS FLOW DIAGRAM
(BASE CASE SCENARIO)

CLIENT: AMERICAN PETROLEUM INSTITUTE

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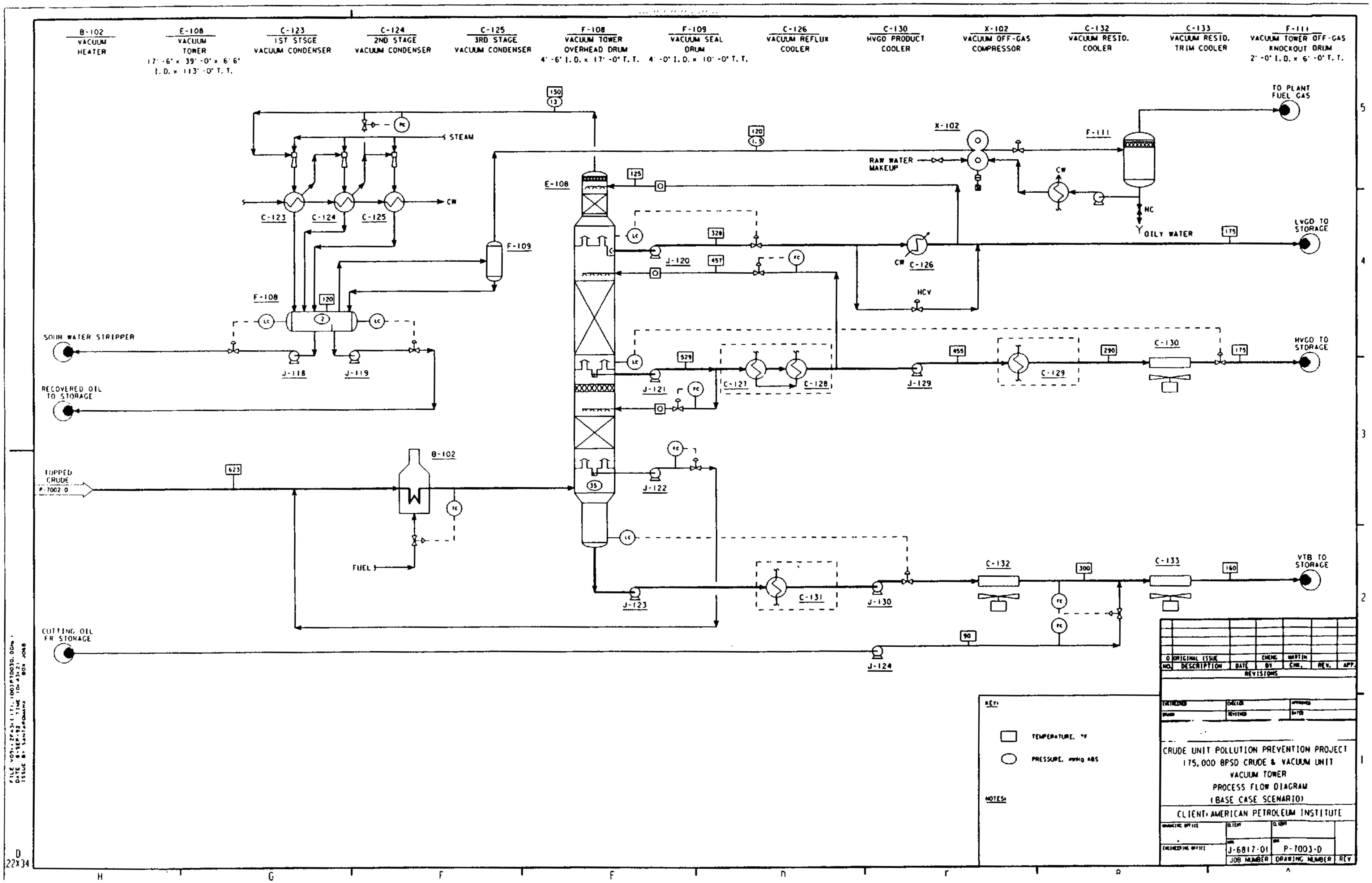
J-6817-01	P-7002-D	


B-102
VACUUM HEATER
E-108
VACUUM TOWER
17'-6" x 39'-0" x 6'6" I.D. x 113'-0" T.T.
C-123
1ST STSGE VACUUM CONDENSER
C-124
2ND STAGE VACUUM CONDENSER
C-125
3RD STAGE VACUUM CONDENSER
F-108
VACUUM TOWER OVERHEAD DRUM
4'-6" I.D. x 17'-0" T.T.
F-109
VACUUM SEAL DRUM
4'-0" I.D. x 10'-0" T.T.
C-126
VACUUM REFLUX COOLER
C-130
HVGO PRODUCT COOLER
X-102
VACUUM OFF-GAS COMPRESSOR
C-132
VACUUM RESID. COOLER
C-133
VACUUM RESID. TRIM COOLER
F-111
VACUUM TOWER OFF-GAS KNOCKOUT DRUM
2'-0" I.D. x 6'-0" T.T.
TO PLANT FUEL GAS
150
13
STEAM
PC
CW
120
1.5
X-102
F-111
RAW WATER MAKEUP
NC
OILY WATER
175
LVGO TO STORAGE
125
E-108
LC
328
J-120
457
FC
C-126
HCV
F-109
F-108
120
2
SOUR WATER STRIPPER
J-118
J-119
RECOVERED OIL TO STORAGE
529
C-127
C-128
J-121
455
J-129
C-129
290
C-130
HVGO TO STORAGE
TOPPED CRUDE
P-7002-D
623
B-102
TC
FUEL
35
J-122
J-123
C-131
J-130
C-132
300
C-133
160
VTB TO STORAGE
90
CUTTING OIL FR STORAGE
J-124
KEY:
TEMPERATURE, °F
PRESSURE, mmHg ABS
NOTES:
0 ORIGINAL ISSUE CHENG MARTIN
NO. DESCRIPTION DATE BY CHK. REV. APP.
REVISIONS
CRUDE UNIT POLLUTION PREVENTION PROJECT
175,000 BPSD CRUDE & VACUUM UNIT
VACUUM TOWER
PROCESS FLOW DIAGRAM
(BASE CASE SCENARIO)
CLIENT: AMERICAN PETROLEUM INSTITUTE
J-6817-01
P-7003-D
JOB NUMBER
DRAWING NUMBER
REV
D
22X34
H
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E
D
C
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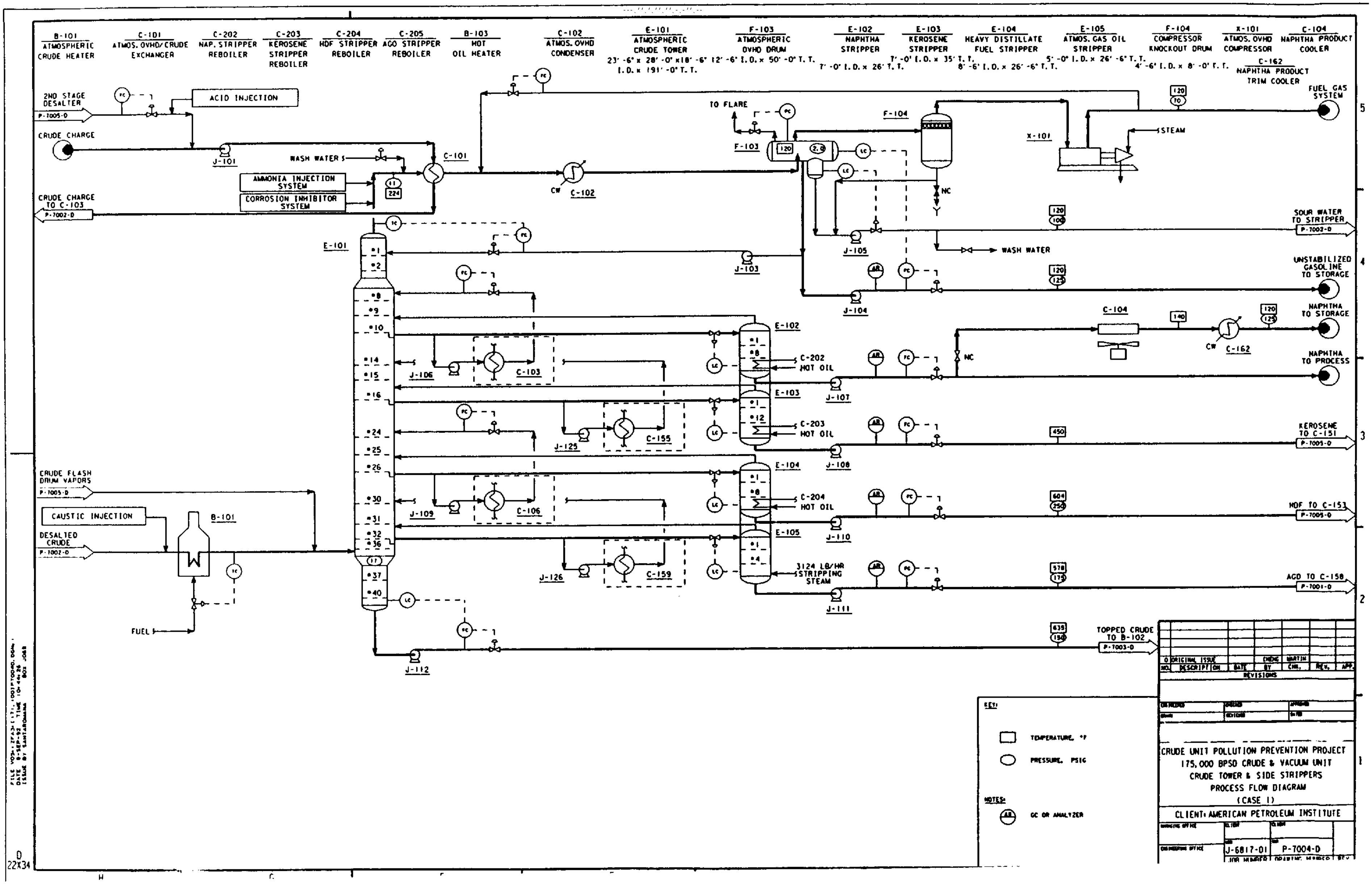
APPENDIX C:

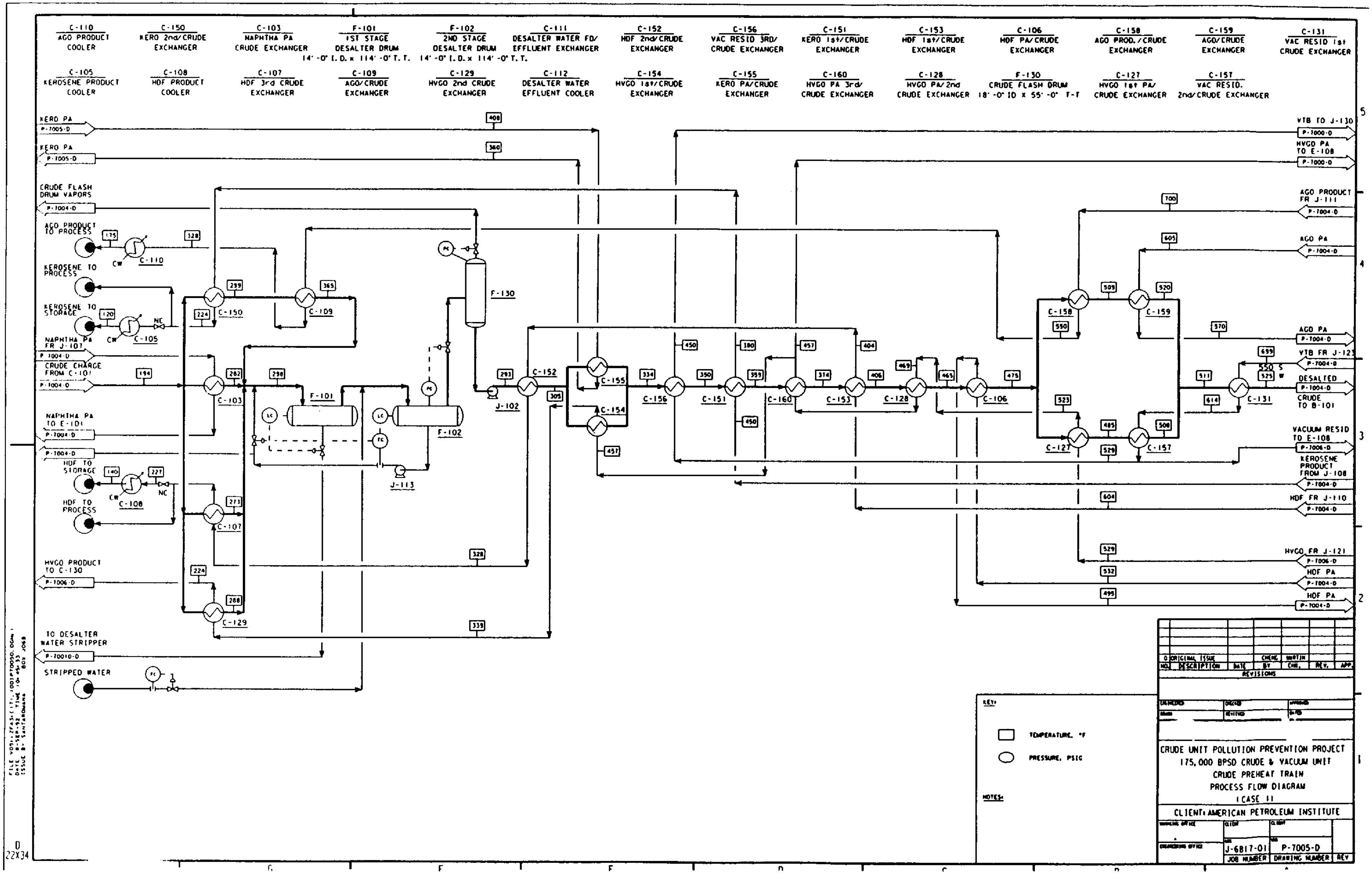
Process Flow Diagrams

for

Case 1



CRUDE UNIT POLLUTION PREVENTION PROJECT
175,000 BPSD CRUDE & VACUUM UNIT
CRUDE TOWER & SIDE STRIPPERS
PROCESS FLOW DIAGRAM
(CASE I)


C-110 AGO PRODUCT COOLER
C-150 KERO 2nd/CRUDE EXCHANGER
C-103 NAPHTHA PA CRUDE EXCHANGER
F-101 1ST STAGE DESALTER DRUM 14'-0" I.D. x 114'-0" T.T.
F-102 2ND STAGE DESALTER DRUM 14'-0" I.D. x 114'-0" T.T.
C-111 DESALTER WATER FD/ EFFLUENT EXCHANGER
C-152 HDF 2nd/CRUDE EXCHANGER
C-156 VAC RESID 3RD/ CRUDE EXCHANGER
C-151 KERO 1st/CRUDE EXCHANGER
C-153 HDF 1st/CRUDE EXCHANGER
C-106 HDF PA/CRUDE EXCHANGER
C-158 AGO PROD./CRUDE EXCHANGER
C-159 AGO/CRUDE EXCHANGER
C-131 VAC RESID 1st CRUDE EXCHANGER
C-105 KEROSENE PRODUCT COOLER
C-108 HDF PRODUCT COOLER
C-107 HDF 3rd CRUDE EXCHANGER
C-109 AGO/CRUDE EXCHANGER
C-129 HVGO 2nd CRUDE EXCHANGER
C-112 DESALTER WATER EFFLUENT COOLER
C-154 HVGO 1st/CRUDE EXCHANGER
C-155 KERO PA/CRUDE EXCHANGER
C-160 HVGO PA 3rd/ CRUDE EXCHANGER
C-128 HVGO PA/2nd CRUDE EXCHANGER
F-130 CRUDE FLASH DRUM 18'-0" ID x 55'-0" T-T
C-127 HVGO 1st PA/ CRUDE EXCHANGER
C-157 VAC RESID. 2nd/CRUDE EXCHANGER
KERO PA P-7005-D
KERO PA P-7005-D
CRUDE FLASH DRUM VAPORS P-1004-D
AGO PRODUCT TO PROCESS
KEROSENE TO PROCESS
KEROSENE TO STORAGE
NAPHTHA PA FR J-107 P-1004-D
CRUDE CHARGE FROM C-101 P-1004-D
NAPHTHA PA TO E-101 P-1004-D
P-1004-D
HDF TO STORAGE
HDF TO PROCESS
HVGO PRODUCT TO C-130 P-1006-D
TO DESALTER WATER STRIPPER P-70010-D
STRIPPED WATER
VTB TO J-130 P-1000-D
HVGO PA TO E-108 P-1000-D
AGO PRODUCT FR J-111 P-1004-D
AGO PA P-1004-D
AGO PA P-1004-D
VTB FR J-121 P-1004-D
DESALTED CRUDE TO B-101 P-1004-D
VACUUM RESID TO E-108 P-1006-D
KEROSENE PRODUCT FROM J-108 P-1004-D
HDF FR J-110 P-1004-D
HVGO FR J-121 P-1006-D
HDF PA P-1004-D
HDF PA P-1004-D
CW
NC
PC
LC
FC
J-102
J-113
408
360
328
175
120
239
224
365
194
282
298
140
227
273
224
288
339
328
293
305
457
334
450
350
180
359
457
314
450
404
406
469
465
475
523
550
509
520
485
529
508
700
605
570
699
550 S
525 W
511
614
604
529
532
495
KEY:
TEMPERATURE, °F
PRESSURE, PSIG
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NO. DESCRIPTION DATE BY CHK. REV. APP.
REVISIONS
CRUDE UNIT POLLUTION PREVENTION PROJECT
175,000 BPSD CRUDE & VACUUM UNIT
CRUDE PREHEAT TRAIN
PROCESS FLOW DIAGRAM
(CASE 1)
CLIENT: AMERICAN PETROLEUM INSTITUTE
J-6817-01 JOB NUMBER
P-7005-D DRAWING NUMBER
REV
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22X34
1
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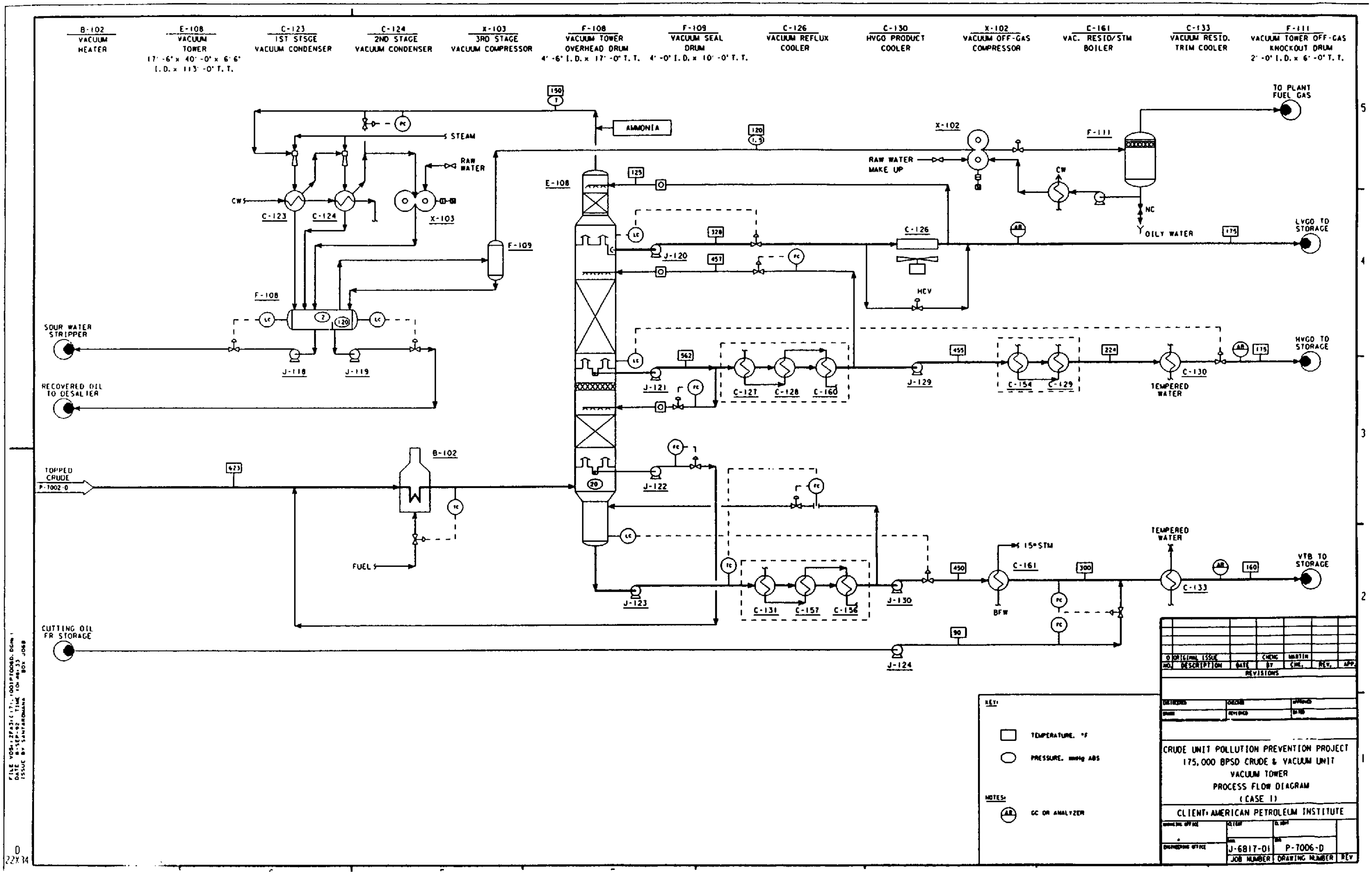
B-102
VACUUM HEATER
E-108
VACUUM TOWER
17'-6" x 40'-0" x 6'6" I.D. x 113'-0" T.T.
C-123
1ST STSGE VACUUM CONDENSER
C-124
2ND STAGE VACUUM CONDENSER
X-103
3RD STAGE VACUUM COMPRESSOR
F-108
VACUUM TOWER OVERHEAD DRUM
4'-6" I.D. x 17'-0" T.T.
F-109
VACUUM SEAL DRUM
4'-0" I.D. x 10'-0" T.T.
C-126
VACUUM REFLUX COOLER
C-130
HVGO PRODUCT COOLER
X-102
VACUUM OFF-GAS COMPRESSOR
C-161
VAC. RESID/STM BOILER
C-133
VACUUM RESID. TRIM COOLER
F-111
VACUUM TOWER OFF-GAS KNOCKOUT DRUM
2'-0" I.D. x 6'-0" T.T.
TO PLANT FUEL GAS
AMMONIA
STEAM
RAW WATER
RAW WATER MAKE UP
CW
NC
OILY WATER
LVGO TO STORAGE
HVGO TO STORAGE
VTB TO STORAGE
SOUR WATER STRIPPER
RECOVERED OIL TO DESALTER
TOPPED CRUDE
P-1002-D
CUTTING OIL FR STORAGE
FUEL
BFW
15# STM
TEMPERED WATER
HCV
150
120
1.5
125
328
451
562
623
455
224
175
115
450
300
160
90
2
20
J-118
J-119
J-120
J-121
J-122
J-123
J-124
J-129
J-130
C-127
C-128
C-160
C-154
C-129
C-131
C-157
C-156
LC
PC
FC
TC
AR
KEY:
TEMPERATURE, °F
PRESSURE, mmHg ABS
NOTES:
GC OR ANALYZER
0 ORIGINAL ISSUE CHENG MARTIN
NO. DESCRIPTION DATE BY CHK. REV. APP.
REVISIONS
CRUDE UNIT POLLUTION PREVENTION PROJECT
175,000 BPSD CRUDE & VACUUM UNIT
VACUUM TOWER
PROCESS FLOW DIAGRAM
(CASE I)
CLIENT: AMERICAN PETROLEUM INSTITUTE
J-6817-01
P-7006-D
JOB NUMBER
DRAWING NUMBER
REV
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22X34
1
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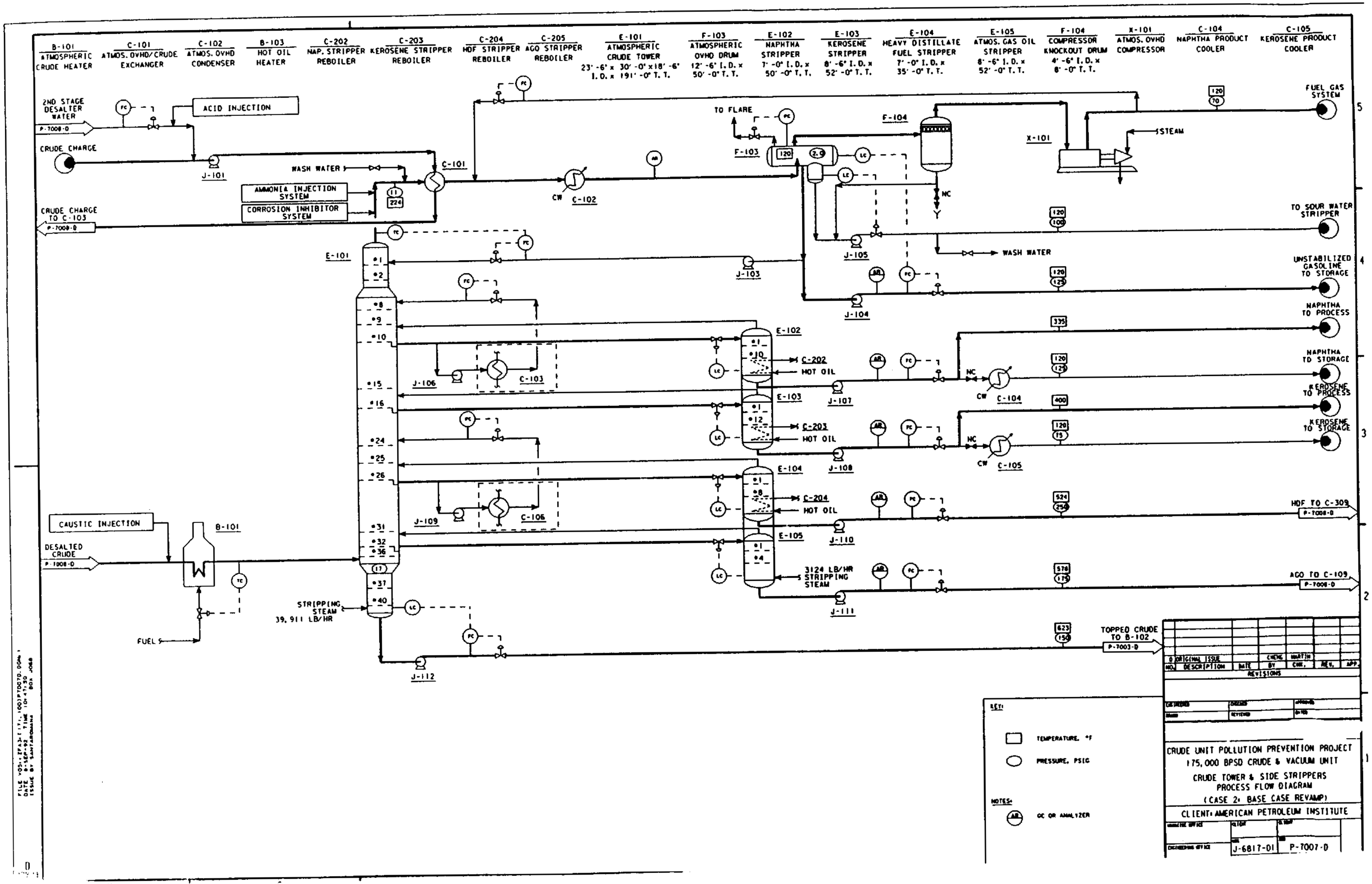
APPENDIX D:

Process Flow Diagrams

for

Case 2


B-101
ATMOSPHERIC CRUDE HEATER
C-101
ATMOS. OVHD/CRUDE EXCHANGER
C-102
ATMOS. OVHD CONDENSER
B-103
HOT OIL HEATER
C-202
NAP. STRIPPER REBOILER
C-203
KEROSENE STRIPPER REBOILER
C-204
HDF STRIPPER REBOILER
C-205
AGO STRIPPER REBOILER
E-101
ATMOSPHERIC CRUDE TOWER
23'-6" x 30'-0" x 18'-6" I.D. x 191'-0" T.T.
F-103
ATMOSPHERIC OVHD DRUM
12'-6" I.D. x 50'-0" T.T.
E-102
NAPHTHA STRIPPER
7'-0" I.D. x 50'-0" T.T.
E-103
KEROSENE STRIPPER
8'-6" I.D. x 52'-0" T.T.
E-104
HEAVY DISTILLATE FUEL STRIPPER
7'-0" I.D. x 35'-0" T.T.
E-105
ATMOS. GAS OIL STRIPPER
8'-6" I.D. x 52'-0" T.T.
F-104
COMPRESSOR KNOCKOUT DRUM
4'-6" I.D. x 8'-0" T.T.
X-101
ATMOS. OVHD COMPRESSOR
C-104
NAPHTHA PRODUCT COOLER
C-105
KEROSENE PRODUCT COOLER
2ND STAGE DESALTER WATER
P-7008-D
FC
ACID INJECTION
CRUDE CHARGE
J-101
WASH WATER
AMMONIA INJECTION SYSTEM
CORROSION INHIBITOR SYSTEM
11
224
C-101
CRUDE CHARGE TO C-103
P-7008-D
FC
CW
C-102
AR
TO FLARE
PC
F-103
120
2.0
LC
F-104
X-101
STEAM
NC
120
70
FUEL GAS SYSTEM
120
100
TO SOUR WATER STRIPPER
WASH WATER
J-105
E-101
J-103
J-104
120
125
UNSTABILIZED GASOLINE TO STORAGE
335
NAPHTHA TO PROCESS
120
125
NAPHTHA TO STORAGE
400
KEROSENE TO PROCESS
120
15
KEROSENE TO STORAGE
E-102
C-202
HOT OIL
J-107
C-104
E-103
C-203
HOT OIL
J-108
C-105
E-104
C-204
HOT OIL
J-110
524
250
HDF TO C-309
P-7008-D
E-105
3124 LB/HR STRIPPING STEAM
J-111
578
175
AGO TO C-109
P-7008-D
J-106
C-103
J-109
C-106
1
2
8
9
10
15
16
24
25
26
31
32
36
17
37
40
1
10
1
12
1
8
1
4
CAUSTIC INJECTION
B-101
TC
DESALTED CRUDE
P-1008-D
FUEL
STRIPPING STEAM 39,911 LB/HR
LC
J-112
623
150
TOPPED CRUDE TO B-102
P-7003-D
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NO. DESCRIPTION
DATE
CHENG BY
MARTIN CHK.
REV.
APP.
REVISIONS
KEY:
TEMPERATURE, °F
PRESSURE, PSIG
NOTES:
QC OR ANALYZER
CRUDE UNIT POLLUTION PREVENTION PROJECT
175,000 BPSD CRUDE & VACUUM UNIT
CRUDE TOWER & SIDE STRIPPERS
PROCESS FLOW DIAGRAM
(CASE 2: BASE CASE REVAMP)
CLIENT: AMERICAN PETROLEUM INSTITUTE
J-6817-01
P-7007-D
1
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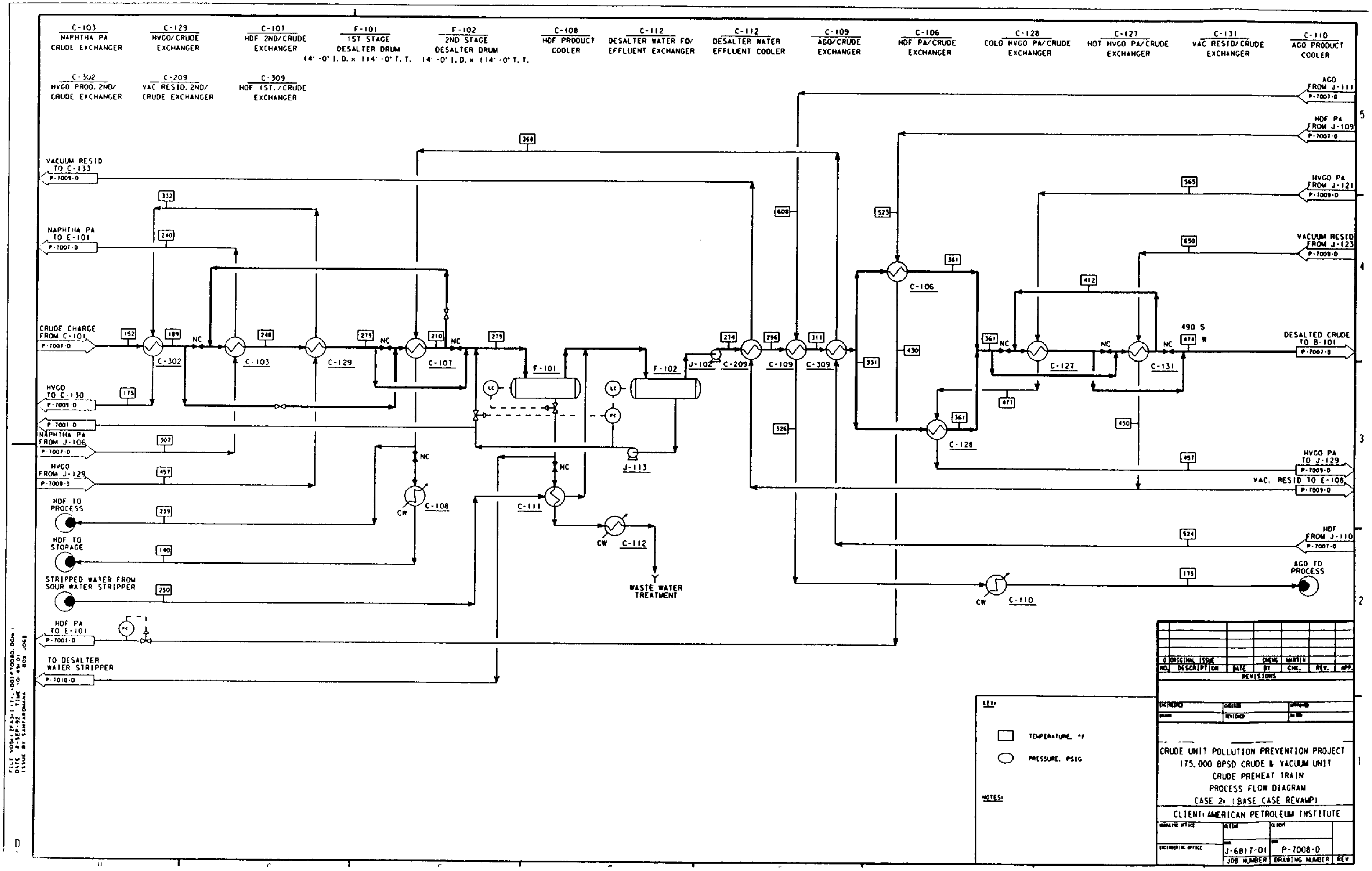
C-103 NAPHTHA PA CRUDE EXCHANGER
C-129 HVGO/CRUDE EXCHANGER
C-107 HDF 2ND/CRUDE EXCHANGER
F-101 1ST STAGE DESALTER DRUM 14'-0" I.D. x 114'-0" T.T.
F-102 2ND STAGE DESALTER DRUM 14'-0" I.D. x 114'-0" T.T.
C-108 HDF PRODUCT COOLER
C-112 DESALTER WATER FD/ EFFLUENT EXCHANGER
C-112 DESALTER WATER EFFLUENT COOLER
C-109 AGO/CRUDE EXCHANGER
C-106 HDF PA/CRUDE EXCHANGER
C-128 COLD HVGO PA/CRUDE EXCHANGER
C-127 HOT HVGO PA/CRUDE EXCHANGER
C-131 VAC RESID/CRUDE EXCHANGER
C-110 AGO PRODUCT COOLER
C-302 HVGO PROD. 2ND/ CRUDE EXCHANGER
C-209 VAC RESID. 2ND/ CRUDE EXCHANGER
C-309 HDF 1ST./CRUDE EXCHANGER
VACUUM RESID TO C-133 P-7009-D
NAPHTHA PA TO E-101 P-7007-D
CRUDE CHARGE FROM C-101 P-7001-D
HVGO TO C-130 P-7009-D
P-7001-D
NAPHTHA PA FROM J-106 P-7007-D
HVGO FROM J-129 P-7009-D
HDF TO PROCESS
HDF TO STORAGE
STRIPPED WATER FROM SOUR WATER STRIPPER
HDF PA TO E-101 P-7001-D
TO DESALTER WATER STRIPPER P-1010-D
AGO FROM J-111 P-7007-D
HDF PA FROM J-109 P-7007-D
HVGO PA FROM J-121 P-7009-D
VACUUM RESID FROM J-123 P-7009-D
DESALTED CRUDE TO B-101 P-7007-D
HVGO PA TO J-129 P-7009-D
VAC. RESID TO E-108 P-7009-D
HDF FROM J-110 P-7007-D
AGO TO PROCESS
WASTE WATER TREATMENT
368
332
240
152
189
248
279
210
279
175
307
457
239
140
250
274
296
311
608
523
326
331
361
430
361
471
361
412
565
650
474
490 S
W
450
457
524
175
NC
C-302
C-103
C-129
C-107
C-108
CW
F-101
F-102
LC
PC
FC
J-102
J-113
C-111
C-112
C-209
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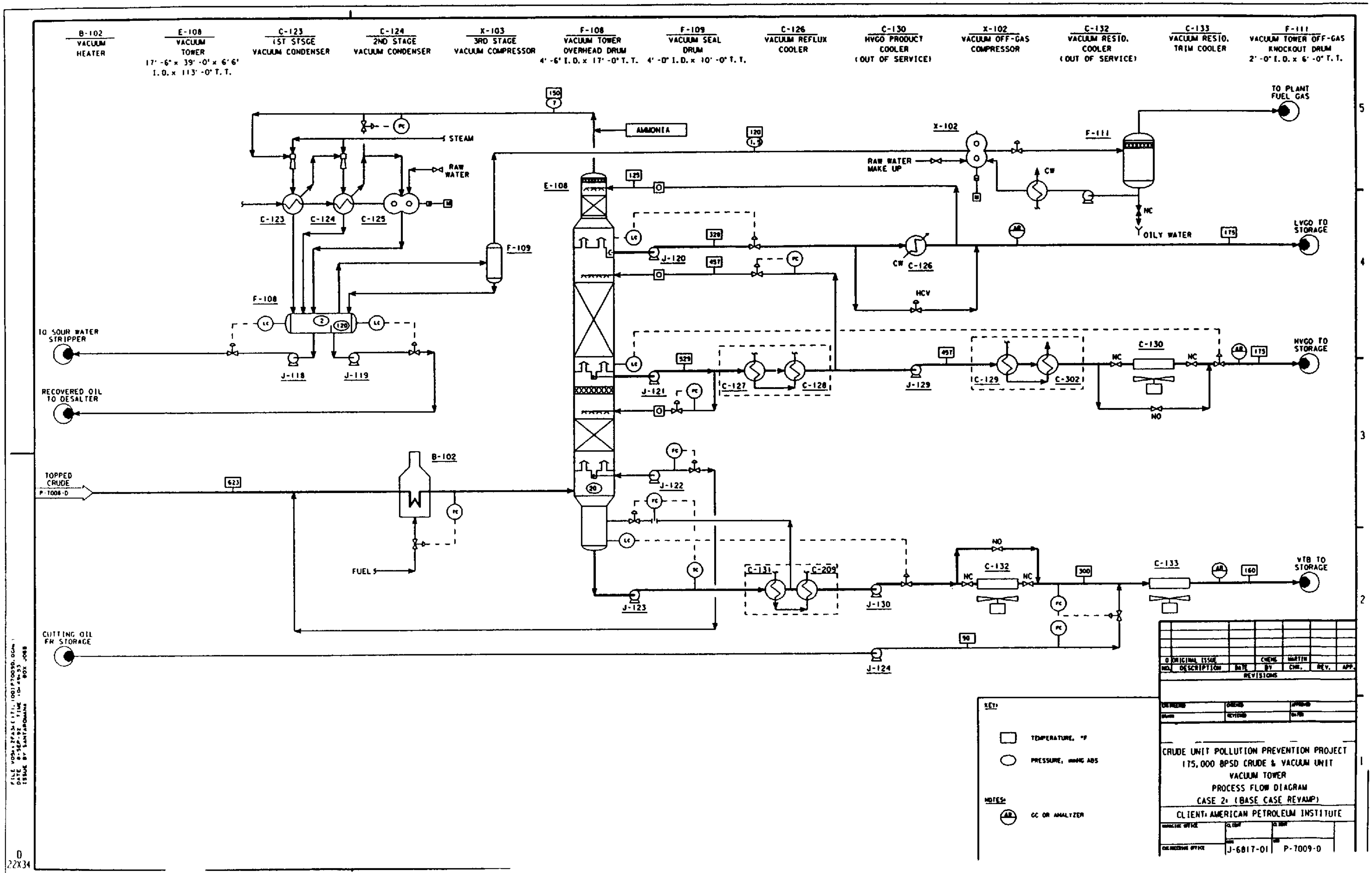
KEY:
TEMPERATURE, °F
PRESSURE, PSIG
NOTES:
0 ORIGINAL ISSUE CHENG MARTIN
NO. DESCRIPTION DATE BY CHK. REV. APP.
REVISIONS
DESIGNED
CHECKED
APPROVED
DRAWN
REVISED
CRUDE UNIT POLLUTION PREVENTION PROJECT
175,000 BPSD CRUDE & VACUUM UNIT
CRUDE PREHEAT TRAIN
PROCESS FLOW DIAGRAM
CASE 2: (BASE CASE REVAMP)
CLIENT: AMERICAN PETROLEUM INSTITUTE
MANAGING OFFICE
ENGINEERING OFFICE
J-6817-01
P-7008-D
JOB NUMBER
DRAWING NUMBER
REV


B-102
VACUUM HEATER
E-108
VACUUM TOWER
17'-6" x 39'-0" x 6'6" I.D. x 113'-0" T.T.
C-123
1ST STGE VACUUM CONDENSER
C-124
2ND STAGE VACUUM CONDENSER
X-103
3RD STAGE VACUUM COMPRESSOR
F-108
VACUUM TOWER OVERHEAD DRUM
4'-6" I.D. x 17'-0" T.T.
F-109
VACUUM SEAL DRUM
4'-0" I.D. x 10'-0" T.T.
C-126
VACUUM REFLUX COOLER
C-130
HVGO PRODUCT COOLER (OUT OF SERVICE)
X-102
VACUUM OFF-GAS COMPRESSOR
C-132
VACUUM RESID. COOLER (OUT OF SERVICE)
C-133
VACUUM RESID. TRIM COOLER
F-111
VACUUM TOWER OFF-GAS KNOCKOUT DRUM
2'-0" I.D. x 6'-0" T.T.
150
7
AMMONIA
STEAM
RAW WATER
120
1.9
X-102
F-111
TO PLANT FUEL GAS
RAW WATER MAKE UP
CW
NC
OILY WATER
C-123
C-124
C-125
E-108
125
F-109
LC
328
J-120
457
PC
C-126
CW
HCV
AR
175
LVGO TO STORAGE
F-108
2
120
LC
TO SOUR WATER STRIPPER
J-118
J-119
RECOVERED OIL TO DESALTER
529
J-121
C-127
C-128
457
J-129
C-129
C-302
NC
C-130
NC
NO
AR
175
HVGO TO STORAGE
TOPPED CRUDE
P-7008-D
623
B-102
FUEL
20
PC
J-122
LC
C-131
C-209
J-123
J-130
NO
C-132
NC
NC
300
C-133
AR
160
VTB TO STORAGE
PC
CUTTING OIL FR STORAGE
90
J-124
5
4
3
2
1
0
ORIGINAL ISSUE
CHENG
MARTIN
NO.
DESCRIPTION
DATE
BY
CHK.
REV.
APP.
REVISIONS
KEY:
TEMPERATURE, °F
PRESSURE, mmHG ABS
NOTES:
GC OR ANALYZER
CRUDE UNIT POLLUTION PREVENTION PROJECT
175,000 BPSD CRUDE & VACUUM UNIT
VACUUM TOWER
PROCESS FLOW DIAGRAM
CASE 2: (BASE CASE REVAMP)
CLIENT: AMERICAN PETROLEUM INSTITUTE
J-6817-01
P-7009-0
D
22X34

APPENDIX E:

Major Equipment List

for

Base Case

MAJOR EQUIPMENT LIST

BASE CASE

ITEM #	*DESCRIPTION*
B-101	ATMOSPHERIC CRUDE HEATER
B-102	VACUUM HEATER
C-101	ATMOSPHERIC OVERHEAD TO CRUDE EXCHANGER
C-102	ATMOSPHERIC OVERHEAD CONDENSER
C-103	NAPHTHA PUMPAROUND
C-104	NAPHTHA PRODUCT COOLER
C-105	KEROSENE PRODUCT COOLER
C-106	HEAVY DISTILLATE FUEL PUMPAROUND TO CRUDE
C-107	HEAVY DISTILLATE FUEL PRODUCT TO CRUDE
C-108	HEAVY DISTILLATE FUEL PRODUCT COOLER
C-109	AGO PRODUCT TO CRUDE
C-110	AGO COOLER
C-111	DESALTER WATER PRODUCT TO CRUDE
C-112	DESALTER FEED EFFLUENT COOLER
C-122	SURFACE CONDENSER
C-123	FIRST STAGE VACUUM CONDENSER
C-124	SECOND STAGE VACUUM CONDENSER
C-125	THIRD STAGE VACUUM CONDENSER
C-126	VACUUM REFLUX COOLER
C-127	HOT VACUUM PUMPAROUND TO CRUDE
C-128	COLD VACUUM PUMPAROUND TO CRUDE
C-129	HVGO PRODUCT EXCHANGE
C-130	HVGO PRODUCT COOLER
C-131	VACUUM RESID
C-132	VACUUM RESID COOLER
C-133	VACUUM RESID TRIM COOLER
C-137	SURFACE CONDENSER
C-138	AIR PREHEATER FOR B-101
C-139	AIR PREHEATER FOR B-102
E-101	ATMOSPHERIC CRUDE TOWER
E-102	NAPHTHA STRIPPER COMBINED WITH E-103
E-103	KEROSENE STRIPPER
E-104	HEAVY DISTILLATE FUEL STRIPPER COMBINED WITH E-105
E-105	ATMOSPHERIC GAS OIL STRIPPER
E-108	VACUUM TOWER

MAJOR EQUIPMENT LIST

BASE CASE

ITEM #	***DESCRIPTION***
F-101	FIRST STAGE DESALTER DRUM
F-102	SECOND STAGE DESALTER DRUM
F-103	ATMOSPHERIC OVERHEAD DRUM
F-104	COMPRESSOR K.O. DRUM
F-108	VACUUM TOWER OVERHEAD DRUM
F-109	VACUUM SEAL DRUM
F-110	M.P. CONDENSATE FLASH
F-111	VACUUM TOWER OFF GAS K.O. DRUM
F-112	FUEL GAS K.O. DRUM
F-115	H.P. CONDENSATE FLASH DRUM
F-117	L.P. CONDENSATE FLASH DRUM
F-119	INHIBITOR TANK
F-123	INHIBITOR DAY TANK
F-124	INHIBITOR DAY TANK
F-125	DESALTER CHEMICAL
F-126	DESALTER CHEMICAL DAY TANK
F-127	DESALTER CHEMICAL DAY TANK
F-128	BLOWCASE
FA-101	FLAME ARRESTOR
J-101 A,B,C	CRUDE CHARGE PUMP
J-102 A,B,C	DESALTED CRUDE CHARGE PUMP
J-103 A&B	ATMOSPHERIC REFLUX PUMP
J-104 A&B	ATMOSPHERIC DISTILLATE PUMP
J-105	SOUR WATER PUMP
J-106 A&B	NAPHTHA PUMP AROUND PUMP
J-107 A&B	NAPHTHA PRODUCT PUMP
J-108	KEROSENE PRODUCT PUMP
J-109	HEAVY DISTILLATE FUEL PUMPAROUND PUMP
J-110 A&B	HEAVY DISTILLATE FUEL PUMPAROUND PUMP
J-111 A&B	ATMOSPHERIC GAS-OIL PRODUCT PUMP
J-112 A&B	ATMOSPHERIC RESID PRODUCT PUMP
J-113 A&B	DESALTER WATER PUMP
J-117 A&B	SURFACE CONDENSER CONDENSATE PUMP
J-118 A&B	VACUUM CONDENSATE PUMP
J-119 A&B	VACUUM SLOP OIL PUMP
J-120 A&B	VACUUM TOWER REFLUX & PRODUCT PUMP

MAJOR EQUIPMENT LIST

BASE CASE

ITEM #	***DESCRIPTION***
J-121 A,B,C	HVGO PUMP AROUND PUMP
J-122 A&B	VACUUM RECYCLE PUMP
J-123 A,B,C	VACUUM RESID PUMP
J-124 A&B	CUTTING OIL PUMP
J-127 A&B	CONDENSATE PUMP
J-128 A&B	DESALTER WATER BOOSTER PUMP
J-129 A&B	HVGO PRODUCT PUMP
J-130 A&B	VACUUM RESID BOOSTER PUMP
J-132	PROCESS SEWER SUMP PUMP
J-133	PUMP OUT PUMP
J-134	INHIBITOR TRANSFER PUMP
J-135	FIRST STAGE DESALTER CHEMICAL
J-136	SECOND STAGE DESALTER CHEMICAL
J-137 A&B	SURFACE CONDENSER PUMP
J-138	INHIBITOR INJECTION PUMP
J-139	INHIBITOR INJECTION PUMP
J-140	SEDIMENT WASH DESALTER
J-141	DESALTER CHEMICAL TRANSFER PUMP
JX-104	B-101 F.D. FAN
JX-105	B-101 F.D. FAN
JX-106	B-101 I.D. FAN
JX-107	B-102 F.D. FAN
JX-108	B-102 F.D. FAN
JX-109	B-102 I.D. FAN
L-101 A,B,C	FIRST STAGE EJECTORS
L-102 A,B,C	SECOND STAGE EJECTORS
L-103 A,B,C	THIRD STAGE EJECTORS
LF-101	VACUUM REFLUX STRAINER
LF-102	HVGO PUMPAROUND BASKET STRAINER
LF-103	WASH OIL BASKET STRAINER
LF-104	FUEL OIL STRAINER
LS-101	STEAM SEPARATOR
LS-102	EJECTOR STEAM SEPARATOR

MAJOR EQUIPMENT LIST

BASE CASE

ITEM #	***DESCRIPTION***
SS-101	STEAM SILENCER
X-101 A&B	ATMOSPHERIC OVERHEAD COMPRESSOR
X-102	VACUUM OFF-GAS COMPRESSOR

APPENDIX F:

Major Equipment List

for

Case 1

MAJOR EQUIPMENT LIST

BASE CASE

ITEM #	***DESCRIPTION***
B-101	ATMOSPHERIC CRUDE HEATER
B-102	VACUUM HEATER
B-103	HOT OIL HEATER
C-101	ATMOSPHERIC DHD TO CRUDE EXCHANGER
C-102	ATMOSPHERIC DHD CONDENSER
C-103	NAPHTHA PUMPAROUND
C-104	NAPHTHA PRODUCT COOLER
C-105	KEROSENE PRODUCT COOLER
C-106	HEAVY DISTILLATE FUEL PUMPAROUND TO CRUDE
C-107	HEAVY DISTILLATE FUEL PRODUCT TO CRUDE
C-108	HEAVY DISTILLATE FUEL PRODUCT COOLER
C-109	AGO PRODUCT TO CRUDE
C-110	AGO COOLER
C-111	DESALTER WATER FD/EFFLUENT EX.
C-112	DESALTER FEED EFFLUENT COOLER
C-122	SURFACE CONDENSER
C-123	FIRST STAGE VACUUM CONDENSER
C-124	SECOND STAGE VACUUM CONDENSER
C-126	VACUUM REFLUX COOLER
C-127	HOT VACUUM PUMPAROUND TO CRUDE 1ST
C-128	COLD VACUUM PUMPAROUND/ TO CRUDE 2ND
C-129	HVGO PRODUCT EXCHANGE
C-130	HVGO PRODUCT COOLER
C-131	VACUUM RESID
C-133	VACUUM RESID TRIM COOLER
C-137	SURFACE CONDENSER
C-138	AIR PREHEATER FOR B-101
C-139	AIR PREHEATER FOR B-102
C-150	VACUUM RESID 3RD/CRUDE
C-151	KERO 1ST/CRUDE
C-152	HDF 2ND/CRUDE
C-153	HDF 1ST/CRUDE 2ND/CRUDE
C-154	HVGO 1ST/CRUDE
C-155	KERO/PA COOLER
C-156	VAC RESID/3RD
C-157	VACUUM RESID 2ND/CRUDE

MAJOR EQUIPMENT LIST

BASE CASE

ITEM #	***DESCRIPTION***
C-158	AGO PRODUCT CRUDE
C-159	AGO PA/CRUDE
C-160	HVGO PA 3RD/CRUDE
C-161	VAC RESID/STEAM BOILER
C-162	TEMPERED WATER COOLER
C-163	NAPHTHA PRODUCT TRIM COOLER
C-202	NAP STRIPPER REBOILER
C-203	KERO STRIPPER REBOILER
C-204	HDF STRIPPER REBOILER
C-409	DESALTER WATER STRIPPER OVHD CONDENSER
E-101	ATMOSPHERIC CRUDE TOWER
E-102	NAPHTHA STRIPPER COMBINED WITH E-103
E-103	KEROSENE STRIPPER
E-104	HEAVY DISTILLATE FUEL STRIPPER COMBINED WITH E-105
E-105	ATMOSPHERIC GAS OIL STRIPPER
E-108	VACUUM TOWER
E-109	DESALTER WATER STRIPPER
F-101	FIRST STAGE DESALTER DRUM
F-102	SECOND STAGE DESALTER DRUM
F-103	ATMOSPHERIC OVERHEAD DRUM
F-104	COMPRESSOR K.O. DRUM
F-108	VACUUM TOWER OVERHEAD DRUM
F-109	VACUUM SEAL DRUM
F-110	M.P. CONDENSATE FLASH
F-111	VACUUM TOWER OFF GAS K.O. DRUM
F-112	FUEL GAS K.O. DRUM
F-115	H.P. CONDENSATE FLASH DRUM
F-117	L.P. CONDENSATE FLASH DRUM
F-119	INHIBITOR TANK
F-123	INHIBITOR DAY TANK
F-124	INHIBITOR DAY TANK
F-125	DESALTER CHEMICAL TANK
F-126	DESALTER CHEMICAL DAY TANK
F-127	DESALTER CHEMICAL DAY TANK
F-128	BLOWCASE
F-130	CRUDE FLASH DRUM

MAJOR EQUIPMENT LIST

BASE CASE

ITEM #	*DESCRIPTION*
F-131	TEMPERED WATER STORAGE TANK
FA-101	FLAME ARRESTOR
J-101 A,B,C	CRUDE CHARGE PUMP
J-102 A,B,C	DESALTED CRUDE CHARGE PUMP
J-103 A&B	ATMOSPHERIC REFLUX PUMP
J-104 A&B	ATMOSPHERIC DISTILLATE
J-105	SOUR WATER PUMP
J-106 A&B	NAPHTHA PUMP AROUND PUMP
J-107 A&B	NAPHTHA PRODUCT PUMP
J-108	KEROSENE PRODUCT PUMP
J-109	HEAVY DISTILLATE FUEL PUMPAROUND PUMP
J-110 A&B	HEAVY DISTILLATE FUEL PUMPAROUND PUMP
J-111 A&B	ATMOSPHERIC GAS-OIL PRODUCT PUMP
J-112 A&B	ATMOSPHERIC RESIDE PRODUCT PUMP
J-113 A&B	DESALTER WATER PUMP
J-117 A&B	SURFACE CONDENSER CONDENSATE PUMP
J-118 A&B	VACUUM CONDENSATE PUMP
J-119 A&B	VACUUM SLOP OIL PUMP
J-120 A&B	VACUUM TOWER REFLUX & PRODUCT PUMP
J-121 A,B,C	HVGO PUMP-AROUND PUMP
J-122 A&B	VACUUM RECYCLE PUMP
J-123 A&B	VACUUM RESID PUMP
J-124 A&B	CUTTING OIL PUMP
J-125 A&B	KEROSENE PUMP-AROUND PUMP
J-126 A&B	ATM GAS-OIL PUMP-AROUND PUMP
J-127 A&B	CONDENSATE PUMP
J-128 A&B	DESALTER WATER BOOSTER PUMP
J-129 A&B	HVGO PRODUCT PUMP
J-130 A&B	VACUUM RESID BOOSTER PUMP
J-132	PROCESS SEWER SUMP PUMP
J-133	PUMP OUT PUMP
J-134	INHIBITOR TRANSFER PUMP
J-135	FIRST STAGE DESALTER CHEMICAL
J-136	SECOND STAGE DESALTER CHEMICAL
J-137 A&B	SURFACE CONDENSER PUMP
J-138	INHIBITOR INJECTION PUMP

MAJOR EQUIPMENT LIST

BASE CASE

ITEM #	*DESCRIPTION*
J-139	INHIBITOR INJECTION PUMP
J-140	SEDIMENT WASH DESALTER
J-141	DESALTER CHEMICAL TRANSFER PUMP
J-142	TEMPERED WATER PUMP
JX-104	B-101 F.D. FAN
JX-105	B-101 F.D. FAN
JX-106	B-101 I.D. FAN
JX-107	B-102 F.D. FAN
JX-108	B-102 F.D. FAN
JX-109	B-102 I.D. FAN
L-101 A,B,C	FIRST STAGE EJECTORS
L-102 A,B,C	SECOND STAGE EJECTORS
L-103 A,B,C	THIRD STAGE VACUUM PUMP
LF-101	VACUUM REFLUX STRAINER
LF-102	HVGO PUMPAROUND BASKET STRAINER
LF-103	WASH OIL BASKET STRAINER
LF-104	FUEL OIL STRAINER
LS-101	STEAM SEPARATOR
LS-102	EJECTOR STEAM SEPARATOR
SS-101	STEAM SILENCER
X-101 A&B	ATMOSPHERIC OVERHEAD COMPRESSOR
X-102	VACUUM OFF-GAS COMPRESSOR
X-103	3RD STAGE VACUUM COMPRESSOR

APPENDIX G:

Major Equipment List

for

Case 2

MAJOR EQUIPMENT LIST

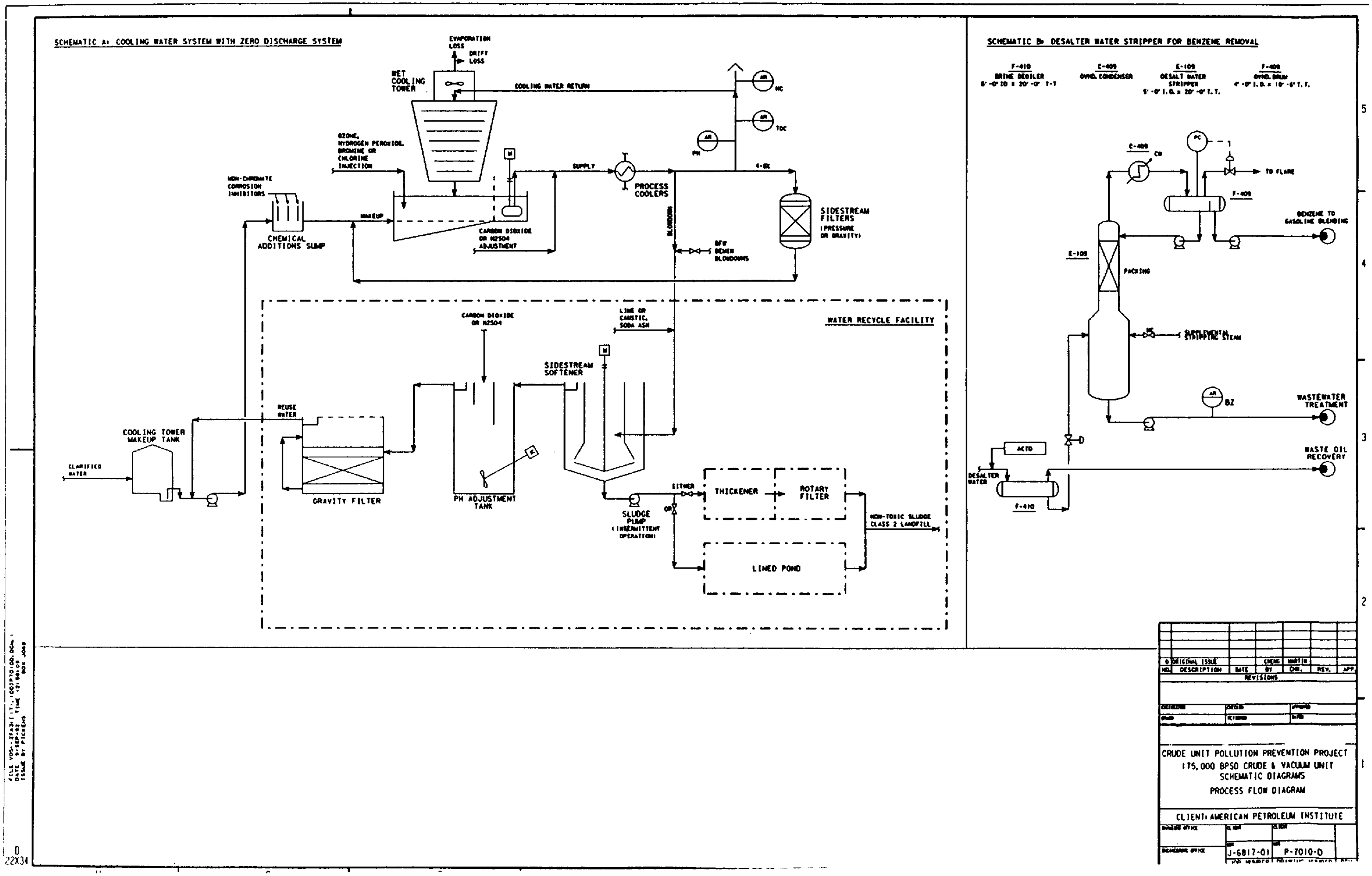
BASE CASE

ITEM #	***DESCRIPTION***
B-103	HOT OIL HEATER
C-109	AGO PRODUCT TO CRUDE
C-202	NAPHTHA STRIPPER REBOILER
C-203	KEROSENE STRIPPER REBOILER
C-204	HDF STRIPPER REBOILER
C-209	VACUUM RESID 2ND/CRUDE
C-302	HVGO PRODUCT 2ND/CRUDE
C-309	HEAVY DISTILLATE FUEL PUMPAROUND TO CRUDE
C-409	BENZENE STRIPPER OVERHEAD CONDENSER
E-102	NAPHTHA STRIPPER COMBINED WITH E-103
E-103	KEROSENE STRIPPER
E-104	HEAVY DISTILLATE FUEL STRIPPER COMBINED WITH E-105
E-105	ATMOSPHERIC GAS OIL STRIPPER
E-109	DESALTER WATER STRIPPER
F-409	OVERHEAD DRUM
F-410	BRINE DE-OILER
X-103	THIRD STAGE VACUUM PUMP

APPENDIX H:

Product Stream Characteristics

Product characteristics are listed in the Stream Summary as per stream number indicated in the simulation diagram.


SCHEMATIC A: COOLING WATER SYSTEM WITH ZERO DISCHARGE SYSTEM
EVAPORATION LOSS
DRIFT LOSS
WET COOLING TOWER
COOLING WATER RETURN
AR
HC
AR
TOC
AR
PH
OZONE, HYDROGEN PEROXIDE, BROMINE OR CHLORINE INJECTION
M
SUPPLY
PROCESS COOLERS
4-6X
NON-CHROMATE CORROSION INHIBITORS
MAKEUP
CHEMICAL ADDITIONS SUMP
CARBON DIOXIDE OR H2SO4 ADJUSTMENT
BLOWDOWN
BFW DEMIN BLOWDOWNS
SIDESTREAM FILTERS (PRESSURE OR GRAVITY)
WATER RECYCLE FACILITY
CARBON DIOXIDE OR H2SO4
LIME OR CAUSTIC, SODA ASH
M
SIDESTREAM SOFTENER
REUSE WATER
COOLING TOWER MAKEUP TANK
CLARIFIED WATER
GRAVITY FILTER
M
PH ADJUSTMENT TANK
EITHER
OR
SLUDGE PUMP (INTERMITTENT OPERATION)
THICKENER
ROTARY FILTER
NON-TOXIC SLUDGE CLASS 2 LANDFILL
LINED POND
SCHEMATIC B: DESALTER WATER STRIPPER FOR BENZENE REMOVAL
F-410
BRINE REBOILER
6'-0" ID x 20'-0" T-T
C-409
OVHD. CONDENSER
E-109
DESALT WATER STRIPPER
5'-0" I.D. x 20'-0" T.T.
F-409
OVHD. DRUM
4'-0" I.D. x 10'-6" T.T.
C-409
CW
PC
TO FLARE
F-409
BENZENE TO GASOLINE BLENDING
E-109
PACKING
SUPPLEMENTAL STRIPPING STEAM
AR
BZ
WASTEWATER TREATMENT
ACID
DESALTER WATER
F-410
WASTE OIL RECOVERY
0 ORIGINAL ISSUE CHENG MARTIN
NO. DESCRIPTION DATE BY CHK. REV. APP.
REVISIONS
CRUDE UNIT POLLUTION PREVENTION PROJECT
175,000 BPSD CRUDE & VACUUM UNIT
SCHEMATIC DIAGRAMS
PROCESS FLOW DIAGRAM
CLIENT: AMERICAN PETROLEUM INSTITUTE
J-6817-01
P-7010-D
5
4
3
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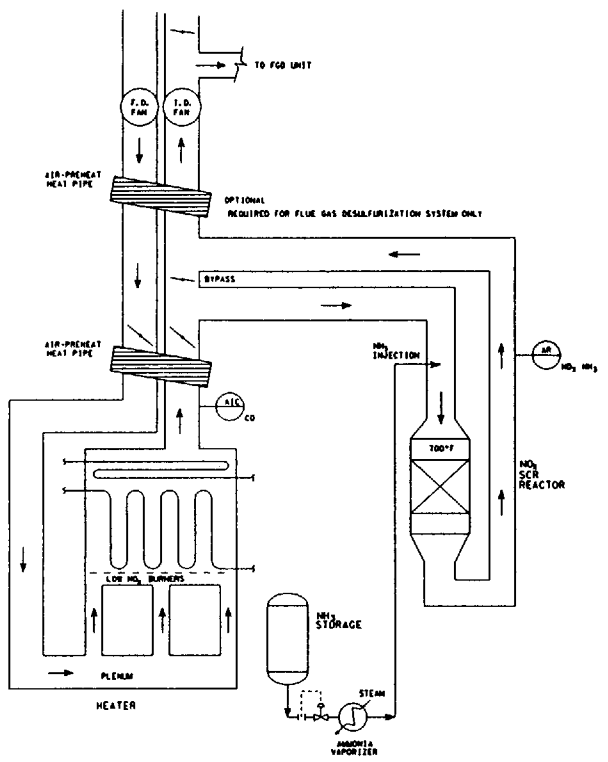
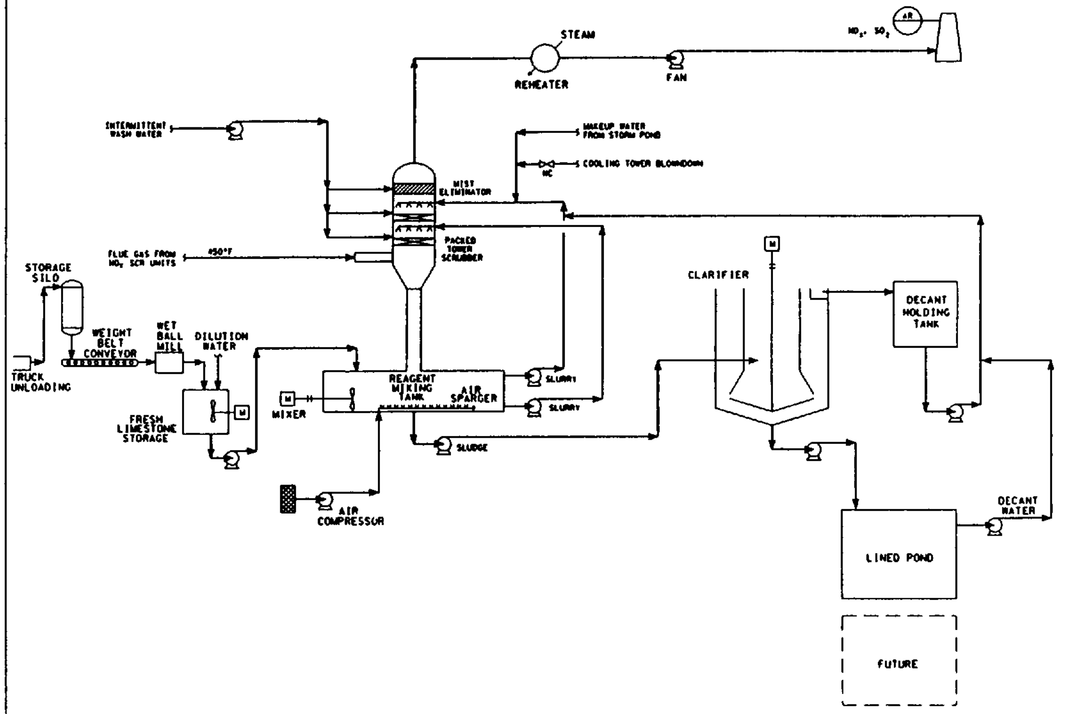
1
D
22X34

SCHEMATIC C: REFINERY NO_X SELECTIVE CATALYTIC REDUCTION UNIT



SCHEMATIC D: WET-LIMESTONE FLUE GAS DESULFURIZATION SYSTEM



NO.	DESCRIPTION	DATE	BY	CHK.	REV.	APP.
0	ORIGINAL ISSUE		CHENG	MARTIN		

REVISIONS

CRUDE UNIT POLLUTION PREVENTION PROJECT
175,000 BPSD CRUDE & VACUUM UNIT
SCHEMATIC DIAGRAMS
PROCESS FLOW DIAGRAM

CLIENT: AMERICAN PETROLEUM INSTITUTE

JOB NUMBER	DRAWING NUMBER	REV
J-6817-01	P-7011-D	

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DATE 9-SEP-92 TIME 12:51:05
ISSUE BY PICKENS BOX JO68

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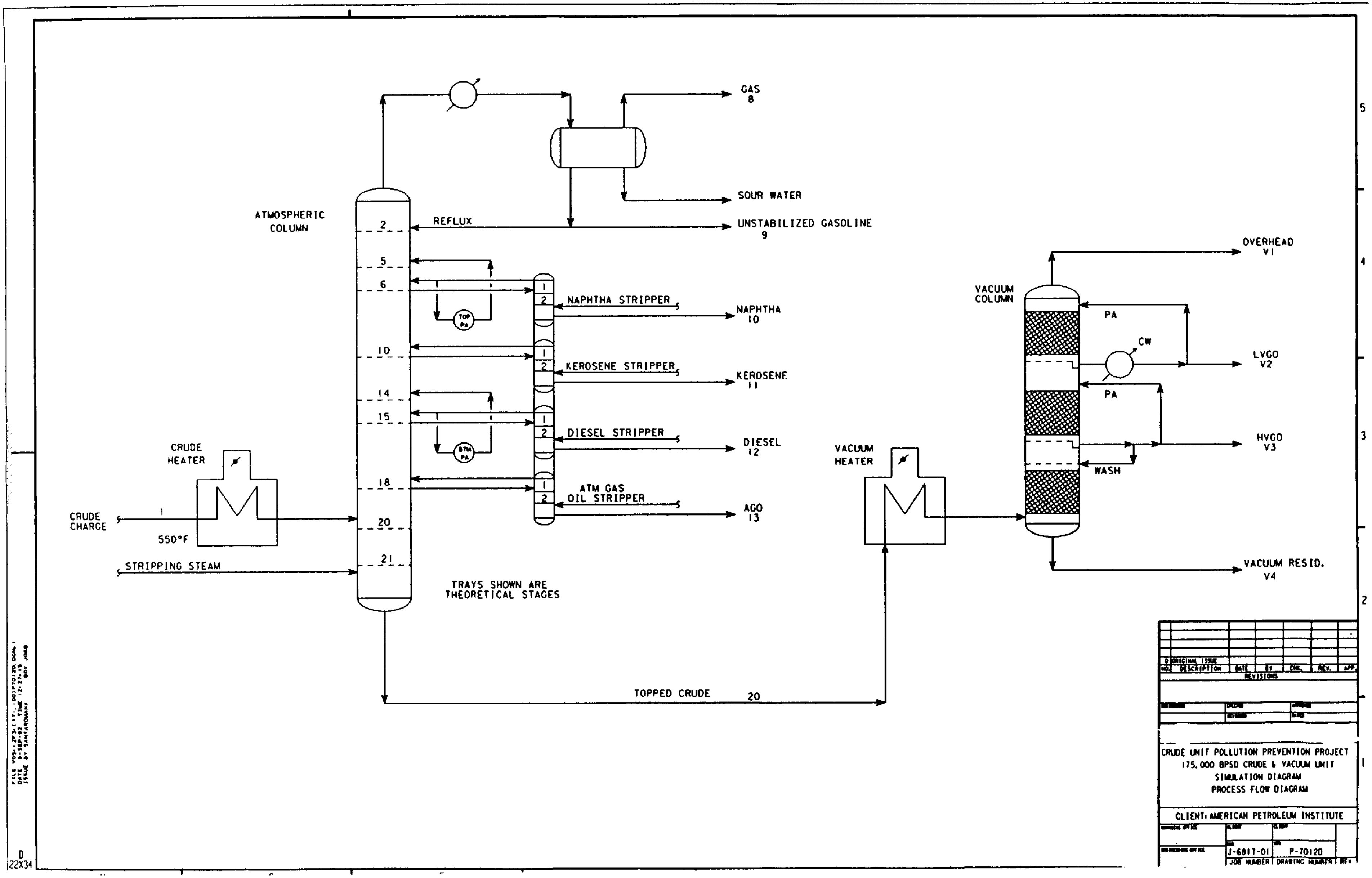
22X34


ATMOSPHERIC COLUMN
CRUDE CHARGE
1
550°F
CRUDE HEATER
STRIPPING STEAM
2
5
6
10
14
15
18
20
21
REFLUX
TOP PA
BTM PA
TRAYS SHOWN ARE THEORETICAL STAGES
GAS 8
SOUR WATER
UNSTABILIZED GASOLINE 9
NAPHTHA STRIPPER
NAPHTHA 10
KEROSENE STRIPPER
KEROSENE 11
DIESEL STRIPPER
DIESEL 12
ATM GAS OIL STRIPPER
AGO 13
TOPPED CRUDE 20
VACUUM HEATER
VACUUM COLUMN
OVERHEAD V1
PA
CW
LVGO V2
PA
HVGO V3
WASH
VACUUM RESID. V4
0 ORIGINAL ISSUE
NO. DESCRIPTION DATE BY CHK. REV. APP.
REVISIONS
CRUDE UNIT POLLUTION PREVENTION PROJECT
175,000 BPSD CRUDE & VACUUM UNIT
SIMULATION DIAGRAM
PROCESS FLOW DIAGRAM
CLIENT: AMERICAN PETROLEUM INSTITUTE
J-6817-01
P-70120
JOB NUMBER DRAWING NUMBER REV
0
22X34
1
2
3
4
5

Product Stream Characteristics

Stream ID	1	8	9	10
Name	Crude Charge	Wet Gas	Unstab. Gasoline	Naphtha
BPSD (MMSCFD)	175,000	(4.79)	35,008	14,880
Gravity, 0API (S.G.)	34.5	(2.00)	70.9	50.8
Lbmoles/hr	9,976	526	3,780	1,175
Molecular Wt.	219.4	58.0	94.5	143.4
<u>ASTM D-86, 0F</u>				
0 LV Percent	96		48	299
5	178		101	314
10	237		133	320
30	408		169	327
50	579		213	341
70	775		246	352
90	1064		284	364
95	1158		299	377
100	1246		320	399
<u>Component, Mol%</u>				
Water	10.1			
Nitrogen		1.4		
H_2S		0.1		
Ethane		2.3		
Propane		21.8		
Isobutane		9.8		
Normal Butane		21.4		
C_5+	33.1			

Product Stream Characteristics

Stream ID	11	12	13	20
Name	Kerosene	Diesel	Atmos. Gas Oil	Topped Crude
BPSD (MMSCFD)	18,216	26,090	8,929	71,958
Gravity, 0API (S.G.)	43.9	34.8	27.3	15.5
Lbmoles/hr	1,213	1,374	387	1,780
Molecular Wt.	176.7	235.7	300.0	477.8
ASTM D-86, 0F				
0 LV Percent	359	419	489	492
5	393	493	584	626
10	404	509	612	666
30	422	534	652	781
50	436	555	672	895
70	451	580	695	1039
90	476	623	738	1276
95	489	644	762	1363
100	516	678	817	1363

Stream ID	V1	V2	V3
Name	LVGO	HVGO	Vacuum Resid
BPSD (MMSCFD)	20,488	25,974	25375
Gravity, 0API (S.G.)	25.6	17.5	6.5

Product Stream Characteristics

Lbmoles/hr	827	765	497
Molecular Wt.	325.6	470.7	764.6
ASTM D-86, 0F			
0 LV Percent	496	699	771
5	588	768	919
10	621	791	966
30	678	840	1061
50	710	881	1130
70	743	924	1247
90	800	993	1360
95	827	1021	1360
100	891	1068	1360

APPENDIX I:

Crude Preheat Train

Pinch Analysis

Crude Preheat Train Pinch Analysis

Introduction

Major advances have been made in recent years in understanding the design of efficient heat recovery networks. Energy integration, or pinch analysis, has emerged as a powerful tool for the evaluation of total systems designs. Pinch analysis identifies the fundamental temperature constraint - the process "pinch" temperature - which thermodynamically limits energy recovery in a system. Stated simply, it provides a structured approach to understand the heat flows within a process. Identification of this constraint makes it possible to establish practical standards for the capital and operating costs of energy systems before they are designed, or in the case of existing systems, before they are modified.

Pinch analysis and heat exchanger network design techniques were used to rate and analyze the base case crude preheat train design, to revamp the base case for improved energy efficiency, and to design a new preheat train for the model new crude unit. A commercial heat exchanger network simulation program was used throughout the study. Initially it was used to rate the base case design and then it was used to aid in the development of the revamp and new design cases. Stream properties for the pinch analysis were extracted from process simulations of the base case and the new case.

Base Case Analysis

The existing preheat train arrangement was rated for Light Arabian Crude. The rating procedure in the exchanger network simulation program was used to perform a rigorous rating of the exchanger network based on the supplied exchanger geometry information, taken from the original exchanger data sheets and stream properties taken from the process simulations. The program was used to established a base case utility usage as well as the crude temperature at inlet to the furnace. The rating indicated that the base case network design could achieve a crude temperature of 4400 °F at the inlet to the furnace.

Analysis of the Model New Crude Unit (Case 1)

Composite curves were generated and utility targets were established for the new design which included four pumparounds and reboiled side strippers. Utilizing the pinch design method for heat exchanger network design, a new network was designed to achieve these utility targets.

Again, the rating procedure in the exchanger network program was used to simulate the new network. The exchangers were rated based on the heat to be exchanged by each of the exchangers, along with stream properties, exchanger shell type and maximum tube length. The simulation results were used to compare the total surface area of the new network to the base case design. The new network required 1.18 times the area of the base case design for a reduction in energy of about 24% of the total base case duty (assuming the crude is to be heated to 6680 °F in the crude heater).

Revamp of Existing Preheat Train (Case 2)

A target for the maximum furnace inlet temperature was set for the base case design from the base case heat composite curves, Figure I-1. These curves represent the heating curve for the crude and the combined "composite" cooling curves for all the other process streams (pumparounds, products, etc.). The maximum furnace inlet temperature was 5100 °F (assuming a drop of 50 °F in the desalter) for a minimum heat exchange approach temperature of 300 °F. This target represents the maximum achievable furnace inlet temperature for the base case design if the preheat train was to be completely redesigned. The goal of the retrofit was to modify the base case network design to more closely approach the target furnace inlet temperature. However, for the retrofit of an existing network, this temperature is not usually an economic or practical goal, it just sets the upper bound for the crude preheat design.

In order for the retrofit to be both economical and practical, it is necessary to understand and compare how the heat flows in the base case design and the ideal heat flows required to achieve the target design. In the ideal design there would be no heat transfer across the pinch point. Hence, to more closely approach the target in the retrofit design, only those exchangers in the base case design that transfer heat across the pinch should be modified/retrofitted. These exchangers can be readily identified once the process pinch has been determined. Beginning at the process pinch point and moving away, a sequence of matches between hot streams and the crude were chosen so as to reduce heat transfer across the pinch.

In this way, only those exchangers transferring heat across the pinch were affected and so modifications to the network were kept to a minimum. Also, the additional heat exchange area required was kept to a minimum by analyzing the U*A product value for each exchanger and by forcing additional surface area requirements into those exchangers with surplus heat exchange area. The final retrofit design required three new exchangers with a combined area of 8.2% of the base case, an additional shell for exchanger C-109 with an additional area of 0.9% of the base case, and changing the sequence of the exchangers by placing exchanger C-107 before exchanger C-103 and exchanger C-101 ahead of exchanger C-127 in the existing network. This modified network is depicted in the PFDs. With this arrangement, the crude temperature at the furnace inlet was calculated to be 4900 °F.

APPENDIX J:

Economic Analysis

Economic Analysis Worksheet
for Two Selective Catalytic Reduction (SCR) Systems
(one for Atmospheric Crude Heater and one for Vacuum Heater)

Case 1 with Fuel Gas

Reference on methodology: OAQPS Control Cost Manual, 4th ed.
Report No. EPA/450/3-90/006, Jan 1990.

		[$]
Total Installed Cost (TIC) for two SCR's	TIC =	$9,070,000
Total Annual Cost (TAC)		
Direct Annual Costs (DC)		
Labor: Operator, hourly rate = $15.00		13,600
Supervisor, rate = $17.50		2,000
Maintenance Materials & Labor (2% of TIC)		181,400
Electricity ($0.07/kWh)		0
Steam ($5.00/1000lb)		5,000
Fuel Gas ($2.85/MMBTU)		0
Catalyst & Ammonia		500,000
Catalyst Take-Back Charge @ $25/cf		42,500
	DC =	$744,500
Indirect Annual Costs (IC)		
Overhead (60% of Labor + Materials)		118,200
G&A (4% of TIC)		362,800
Capital Recovery Factor (CRF) = 0.1770 (for i = 12% , n = 10 years)		
Capital Recovery Cost (CRF x TIC)		1,605,246
	IC =	$2,086,246
Recovery Credits (RC)	RC =	$0
TOTAL ANNUAL COST (TAC = DC + IC - RC)		$2,830,746
NOx reduction available from this technology (tons/year)		100
ANNUALIZED COST PER TON OF NOx REMOVED		$28,428

Appendix J
Economic Analysis Worksheet
for Two Selective Catalytic Reduction (SCR) Systems
(one for Atmospheric Crude Heater and one for Vacuum Heater)

Case 1 with 1 wt% S Fuel Oil

Reference on methodology: OAQPS Control Cost Manual, 4th ed.
Report No. EPA/450/3-90/006, Jan 1990.

		[$]
Total Installed Cost (TIC)		
	TIC =	$9,070,000
Total Annual Cost (TAC)		
Direct Annual Costs (DC)		
Labor: Operator, hourly rate = $15.00		13,600
Supervisor, rate = $17.50		2,000
Maintenance Materials & Labor (2% of TIC)		181,400
Electricity ($0.07/kWh)		0
Steam ($5.00/1000lb)		5,000
Fuel Gas ($2.85/MMBTU)		0
Catalyst & Ammonia		1,000,000
Catalyst Take-Back ($25/cf)		85,000
	DC =	$1,287,000
Indirect Annual Costs (IC)		
Overhead (60% of Labor + Materials)		118,200
G&A (4% of TIC)		362,800
Capital Recovery Factor (CRF) = 0.1770 (for i = 12% , n = 10 years)		
Capital Recovery Cost (CRF x TIC)		1,605,246
	IC =	$2,086,246
Recovery Credits (RC)	RC =	$0
TOTAL ANNUAL COST (TAC = DC + IC - RC)		$3,373,246
NOx reduction available from this technology (tons/year)		168.4
ANNUALIZED COST PER TON OF NOx REMOVED		$20,031

Economic Analysis Worksheet
for VOC Reduction
(includes upgraded pump seals, upgraded valves & flanges, MDO system, and benzene removal stripper)

Case 1

Reference on methodology: OAQPS Control Cost Manual, 4th ed.
Report No. EPA/450/3-90/006, Jan 1990.

		[$]
Total Installed Cost (TIC)		
	TIC =	$2,687,000
Total Annual Cost (TAC)		
Direct Annual Costs (DC)		
Labor: Operator, hourly rate =	$15.00	124,800
Supervisor, rate =	$17.50	18,720
Maintenance Materials & Labor (2% of TIC)		53,740
	DC =	$197,260
Indirect Annual Costs (IC)		
Overhead (60% of Labor + Materials)		118,356
G&A (4% of TIC)		107,480
Capital Recovery Factor (CRF) = 0.1770 (for i = 12% , n = 10 years)		
Capital Recovery Cost (CRF x TIC)		475,556
	IC =	$701,392
Recovery Credits (RC)	RC =	$0
TOTAL ANNUAL COST (TAC = DC + IC - RC)		$898,652
VOC reduction available from this technology (tons/year)		176
ANNUALIZED COST PER TON OF VOC REMOVED		$5,106

Economic Analysis Worksheet
for Two Selective Catalytic Reduction (SCR) Systems
(one for Atmospheric Crude Heater and one for Vacuum Heater)

Case 2 with Fuel Gas

Reference on methodology: OAQPS Control Cost Manual, 4th ed.
Report No. EPA/450/3-90/006, Jan 1990.

		[$]
Total Installed Cost (TIC)		
	TIC =	$10,959,000
Total Annual Cost (TAC)		
Direct Annual Costs (DC)		
Labor: Operator, hourly rate =	$15.00	13,600
Supervisor, rate =	$17.50	2,000
Maintenance Materials & Labor (2% of TIC)		219,180
Electricity ($0.07/kWh)		0
Steam ($5.00/1000lb)		5,500
Fuel Gas ($2.85/MMBTU)		0
Catalyst & ammonia		500,000
Catalyst Take-Back($25/cf)		42,500
	DC =	$782,780
Indirect Annual Costs (IC)		
Overhead (60% of Labor + Materials)		140,868
G&A (4% of TIC)		438,360
Capital Recovery Factor (CRF) = 0.1770		
(for i = 12% , n = 10 years)		
Capital Recovery Cost (CRF x TIC)		1,939,569
	IC =	$2,518,797
Recovery Credits (RC)	RC =	$0
TOTAL ANNUAL COST (TAC = DC + IC - RC)		$3,301,577
NOx reduction available from this technology (tons/year)		117
ANNUALIZED COST PER TON OF NOx REMOVED		$28,228

Appendix J
Economic Analysis Worksheet for Two Selective Catalytic Reduction (SCR) Systems (one for Atmospheric Crude Heater and one for Vacuum Heater)

Case 2 with 1 wt% S Fuel Oil

Reference on methodology: OAQPS Control Cost Manual, 4th ed.
Report No. EPA/450/3-90/006, Jan 1990.

		[$]
Total Installed Cost (TIC)		
	TIC =	$10,959,000
Total Annual Cost (TAC)		
Direct Annual Costs (DC)		
Labor: Operator, hourly rate = $15.00		13,600
Supervisor, rate = $17.50		2,000
Maintenance Materials & Labor (2% of TIC)		219,180
Electricity ($0.07/kWh)		0
Steam ($5.00/1000lb)		5,500
Fuel Gas ($2.85/MMBTU)		0
Catalyst & Ammonia		1,000,000
Catalyst Take-Back ($25/cf)		85,000
	DC =	$1,325,280
Indirect Annual Costs (IC)		
Overhead (60% of Labor + Materials)		140,868
G&A (4% of TIC)		438,360
Capital Recovery Factor (CRF) = 0.1770 (for i = 12% , n = 10 years)		
Capital Recovery Cost (CRF x TIC)		1,939,569
	IC =	$2,518,797
Recovery Credits (RC)	RC =	$0
TOTAL ANNUAL COST (TAC = DC + IC - RC)		$3,844,077
NOx reduction available from this technology (tons/year)		198.5
ANNUALIZED COST PER TON OF NOx REMOVED		$19,366

Appendix J
Economic Analysis Worksheet
for Wet Limestone SO2 Scrubber System
(one system for Atmospheric Crude Heater)

Case 1 with 1 wt% S Fuel Oil

Reference on methodology: OAQPS Control Cost Manual, 4th ed.
Report No. EPA/450/3-90/006, Jan 1990.

		[$]
Total Installed Cost (TIC)		
	TIC =	$5,436,000
Total Annual Cost (TAC)		
Direct Annual Costs (DC)		
Labor: Operator, hourly rate = $15.00		68,000
Supervisor, rate = $17.50		10,200
Maintenance Materials & Labor (2% of TIC)		108,720
Electricity ($0.07/kWh)		210,426
Steam ($5.00/1000lb)		5,000
Makeup water ($0.1/100g)		31,536
Limestone		264,000
Sludge landfill ($50/ton)		178,120
	DC =	$876,002
Indirect Annual Costs (IC)		
Overhead (60% of Labor + Materials)		112,152
G&A (4% of TIC)		217,440
Capital Recovery Factor (CRF) = 0.1770 (for i = 12% , n = 10 years)		
Capital Recovery Cost (CRF x TIC)		962,086
	IC =	$1,291,678
Recovery Credits (RC)	RC =	$0
TOTAL ANNUAL COST (TAC = DC + IC - RC)		$2,167,680
SOx reduction available from this technology (tons/year)		1324.3
ANNUALIZED COST PER TON OF SOx REMOVED		$1,637

Appendix J
Economic Analysis Worksheet for Wet Limestone SO2 Scrubber System (one system for Atmospheric Crude Heater)

Case 2 with 1 wt% S Fuel Oil

Reference on methodology: OAQPS Control Cost Manual, 4th ed.
Report No. EPA/450/3-90/006, Jan 1990.

		[$]
Total Installed Cost (TIC)		
	TIC =	$6,038,000
Total Annual Cost (TAC)		
Direct Annual Costs (DC)		
Labor: Operator, hourly rate = $15.00		68,000
Supervisor, rate = $17.50		10,200
Maintenance Materials & Labor (2% of TIC)		120,760
Electricity ($0.07/kWh)		233,298
Steam ($5.00/1000lb)		5,500
Makeup water ($0.1/100g)		63,072
Limestone		310,671
Sludge landfill ($50/ton)		211,171
	DC =	$1,022,672
Indirect Annual Costs (IC)		
Overhead (60% of Labor + Materials)		119,376
G&A (4% of TIC)		241,520
Capital Recovery Factor (CRF) = 0.1770 (for i = 12% , n = 10 years)		
Capital Recovery Cost (CRF x TIC)		1,068,630
	IC =	$1,429,526
Recovery Credits (RC)	RC =	$0
TOTAL ANNUAL COST (TAC = DC + IC - RC)		$2,452,198
SOx reduction available from this technology (tons/year)		1570.0
ANNUALIZED COST PER TON OF SOx REMOVED		$1,562

Economic Analysis Worksheet
for VOC Reduction
(includes upgraded pump seals, upgraded valves & flanges,
MDO system, and benzene removal stripper)

Case 2

Reference on methodology: OAQPS Control Cost Manual, 4th ed.
Report No. EPA/450/3-90/006, Jan 1990.

		[$]
Total Installed Cost (TIC)		
	TIC =	$2,795,000
Total Annual Cost (TAC)		
Direct Annual Costs (DC)		
Labor: Operator, hourly rate =	$15.00	124,800
Supervisor, rate =	$17.50	18,720
Maintenance Materials & Labor (2% of TIC)		55,900
	DC =	$199,420
Indirect Annual Costs (IC)		
Overhead (60% of Labor + Materials)		119,652
G&A (4% of TIC)		111,800
Capital Recovery Factor (CRF) = 0.1770 (for i = 12% , n = 10 years)		
Capital Recovery Cost (CRF x TIC)		494,671
	IC =	$726,123
Recovery Credits (RC)	RC =	$0
TOTAL ANNUAL COST (TAC = DC + IC - RC)		$925,543
VOC reduction available from this technology (tons/year)		170
ANNUALIZED COST PER TON OF VOC REMOVED		$5,444

APPENDIX K:

Other Studies

Other Studies

Packed Crude Column

For cost comparison purposes, a detailed mechanical vessel analytical design for a packed crude column was carried out. The cost of a packed column is three times higher than a trayed column, even though the diameter of a column with structured packing is 1 to 2 feet smaller. In general, the trade-offs for improved fractionation and reduced energy consumption do not justify a packed column. The feasibility of retrofitting the packed column later for increased throughput and/or crude slate changes is eliminated.

Distributed Distillation for Crude and Vacuum Unit

The main objective of distributed distillation is to reduce energy consumption by performing multiple series of atmospheric and vacuum distillation steps. Maximum utilization of heat recovery is made possible by distributed distillation techniques.

Distributed distillation was specifically excluded from the scope of this study by API, since Kellogg has proprietary execution technology in this area. Kellogg is working in this area and plans to report results at a future date.

Crude Column Without Side Strippers

Process simulation runs were also performed for a crude column with an increased number of theoretical stages and without side strippers in order to eliminate stripping steam usage. In addition to poor front end fractionation, the light sidedraw products do not meet flash point temperature requirements. For safety reasons there will always be a need for sidestrippers on light products (products with flash point below 1400 $_{o}$F) where there is no opportunity to correct the flash point in a downstream processing unit.

For sidedraw products to be hydrotreated, however, flash point correction is accomplished in the hydrotreater stabilizer. Whether or not to use a side stripper then becomes an economic decision. Will the savings in steam generation and water and wastewater treating costs be greater than the increased operating costs on the hydrotreater?

In terms of pollution prevention, eliminating one or more steam-stripped side strippers can potentially reduce the refinery steam production requirements (assuming the stripping steam is not surplus). Benefits include the reductions in boiler feedwater make-up and wastewater generation rates.

In order to eliminate stripping steam to the crude column altogether, the crude column was simulated with fuel gas stripping at the bottom trays, in lieu of using superheated low pressure steam. This is feasible, but it will impose a penalty on the overhead compressor system on power consumption. Since there is no stripping steam, there will be logistic problems for wash water supply on the overhead piping. Without a good source of wash water from the condensed steam, raw water perhaps can be injected to the overhead piping but will create fouling problems on the overhead exchangers. Scale prevention chemicals can be injected into the raw water supply in order to alleviate some of the problems.

Fuel Gas Versus Fuel Oil Firing

The sole selection of fuel gas for 100% firing in all fired heaters may not be realistic for some refiners. Some refiners prefer to have control of a secured fuel source supply, such as fuel oil products produced from the unit. This limits the risk of overdependence on import fuel gas. If every energy user opts for low sulfur fuel gas in order to reduce SO_2 emissions, isolated shortages of sweet fuel gas could occur. Therefore, this study evaluated the scenario where high sulfur fuel oil is used for 100% firing in the crude heater. The study included the design of the SO_X scrubber/removal system. SO_X emissions were calculated based on different sulfur levels in the fuel oil (3.34 wt%, 1 wt%, and 0.2% wt%).

Evaluation of NO_X and SO_X Abatement Technologies

The following post-combustion control technologies were evaluated and discarded for our study because of concerns associated with high capital/operating cost, system complexity, limited applicability, and uncertain field-proven performance:

- Electron beam combined with dry Flue Gas Desulfurization (FGD)
- Multi-stage simultaneous scrubbing for NO_X/SO_X removal
- Selective noncatalytic reduction (SNR)
- Lime spray dryer
- Wet and dry scrubbing for both NO_X/SO_X removal
- Regenerative scrubbers
- Regenerative fixed-bed (Cu0/$CuSO_4$) for catalytic reduction of both NO_x/SO_X
- Two-stage activated-coke-based absorber for simultaneous NO_X/SO_X removal
- Regenerable zinc oxide spray-dryer for both NO_X/SO_X removal
- In-furnace limestone/De-NO_X slurry injection

The presently available control technologies produce either liquid waste, gypsum, sulfur, or sulfuric acid. Each application is site-specific. The salable by-products will create disposal and downstream equipment pollution liabilities if the quantities are small and the markets are too remote.

Wet-limestone Flue Gas Desulfurization (FGD) System

The final step for post-combustion pollution control is the FGD unit (refer to schematic Dwg. P-7011-D) where SO_2 removal is accomplished. SO_2 reacts with the circulating limestone slurry to form calcium sulfite and sulfate. Scrubbed gas passes through a mist eliminator and is reheated before discharging the atmosphere. Gypsum is also formed after oxidation of hydrated calcium sulfite with air. SO_2 removal is estimated to be 90-98% and the sludge will be collected in a lined pond for eventual landfill operation. For greater than 90% removal efficiency, wet scrubbing is to be considered essential and dry limestone spray scrubber followed by a baghouse or electrostatic precipitator will normally achieve 90% removal. Limestone is selected as the principal reagent because it is relatively cheap compared to lime and caustic. The unwanted by-products are gypsum, which can be landfilled as non-hazardous solid waste. No credit is given here, even though there is a possibility that gypsum can be used as construction dry-wall materials. For temporary storage, a lined pond can be built and water can be decanted and reused as makeup water to the packed bed scrubber. Particulate matter removal is also facilitated by the wet scrubbing process, which is estimated to be in the 40% range.

$$CaCO_3 + SO_2 + 2\ H_2O + 1/2\ O_2 = CaSO4 \cdot 2\ H_2O + CO_2$$

Fuel Oil Desulfurization Treatment

Eighty to ninety five percent (80-95%) hydrodesulfurization for the high sulfur fuel oil can be obtained by a fixed bed dual catalyst hydrotreating process. It is not economically feasible to design a small hydrotreater just for the crude heater fuel oil requirements. However, a separate contractor with surplus hydrogen supply can be considered for processing high sulfur fuel oil and multiple clients. It is estimated that the total installed cost for a 20,000 BPSD unit is $112 million and the processing cost is estimated at 2 cents per pound. There are side benefits from hydrotreating high sulfur fuel oil: Fuel nitrogen, metals, asphaltene and carbon residue contents will be reduced as well, thereby producing cleaner fuel oil. Normally 50% nitrogen removal is achievable. From a stoichiometric standpoint, it makes more sense to remove elementary sulfur before burning, as twice its weight in the form of sulfur dioxide will be generated after combustion. The same applies for fuel nitrogen pool in the fuel oil, which will contribute mostly to the formation of nitrogen oxides during combustion (60-80%). To conserve premium fuel such as sweet fuel gas, it is recommended to burn low sulfur fuel oil after hydrodesulfurization and denitrogenation. The incentive to use low sulfur fuel oil is more intensified from the waste disposal standpoint upon examination of wet limestone scrubber operation.

Membrane Technology

New membrane technology which has the potential of handling oily water clean-up is currently under development. Hollow fiber membranes are being used to separate oil and hydrocarbon liquid from water. Oil in the form of droplets do not plug the membrane, but slugs of oil will cause plugging. Typical oily water containing 500 mg/l of oil will produce an effluent water containing 10-15 mg/l of oil. Operating temperatures and pressures are low. At the present time, operating temperature is limited to 1500 $_o$F.

Currently there are no commercial units in operation, only pilot plant information is available. More development in this area is expected in the near future. In comparison to other treatment technologies, capital costs appear to be high.

Theory and Operation of Heat Pipe Heat Exchanger

The heat-pipe air-preheater equipped with the crude furnace is a battery of heat pipes incorporated into a plate fin heat exchanger. Each heat-pipe is made from a fin tube, which is lined internally with some sort of a wick structure containing capillary pores. The fin tube is evacuated and filled with a volatile working fluid, and then permanently sealed. The working fluid is a toluene-like compound , exhibiting the following characteristics:

- High latent heat of vaporization
- Good wetting characteristics (high surface tension)
- High thermal conductivity
- Moderate vapor pressure
- Low freezing point (avoid winter freeze-ups)
- Low viscosity
- Volatility

The heat-pipe operates as a closed loop evaporation/condensation cycle, which continues as long as there is a temperature driving force across the surface area. Heat applied at one end of the tube causes the working fluid to evaporate at a high rate. Due to the pressure differences created within the tube, the vapor migrates to the cooler part of the tube, where it condenses, releasing its latent heat of condensation. The condensed fluid will then flow back into the evaporation section. In the evaporation section, the capillary wick grooved into the inner tube surface distributes the working fluid over the entire wetted surface for maximum heat transfer. In the condensation section, the wick provides a drainage path for the condensed fluid and hence prevents intermixing of the liquid and vapor streams.

As a counterflow air-to-air heat exchanger, the air-preheater is tilted at 70 from the horizontal plane such that the evaporation section is below the condensation section. Accordingly, the condensed working fluid flow is assisted by gravity. A sealed partition plat separates the hot flue gases (driven by an induced draft fan) from the cold makeup air (driven by a forced draft fan). In order to reduce flow-induced vibration, a vibration plat is inserted in the flue gas section. Each heat pipe is also equipped with a compression spring to allow for expansion and/or contraction.

Since the air-preheater has no moving parts, maintenance is limited to periodic inspection. If cleaning is required, steam jetting will be the preferred method without removing the exchanger and two fans.

Desalting System

Refiners processing heavy crudes will have greater problems in the desalting system than was considered in this study. Persistent oil carryunder, water carryover and the development of a stable emulsion band (rag layer) at the interface are some of the problems not addressed. Desalter system modifications (newer technology) and the development of problem-specific chemicals by a chemical vendor solved these problems in one refinery (reference 17).

Some refiners favor the installation of a flash drum immediately downstream of the desalter on their crude units. Dehydration of the desalted crude will occur in this drum if the temperature is high enough, thus removing any free water carryover. The flash drum bottoms temperature must be higher than the boiling point of saturated water at flash drum pressure to ensure vaporization of the water.

Oil carryunder and rag layer problems, once developed, become treatment problems rather than pollution prevention problems. Brine de-oiling is being used in some refineries to reduce the amount of oil and solids being dumped to the sewer. A sponge oil and/or acid is added to the desalter brine to separate oil from the brine. The sponge oil and the recoverd oil are then decanted from the water and recycled back to the crude feed pumps.

APPENDIX L:

List of Acronyms

ACRONYMS USED IN THIS REPORT

AGO	Atmospheric Gas Oil
API	American Petroleum Institute
BACT	Best Available Control Technology
BAT	Best Available Technology Economically Achievable
BCT	Best Conventional Pollutant Control Technology
BOD	Biological Oxygen Demand
BPSD	Barrels Per Stream Day
BPT	Best Practicable Control Technology Currently Available
BS&W	Bottoms, sediment, and water
BTU	British Thermal Unit
CAA	Clean Air Act
CAAA	1990 Amendments to Clean Air Act
CFR	Code of Federal Regulations
CO	Carbon Monoxide
COD	Chemical Oxygen Demand
CPI	Corrugated Plate Interceptor
CREC	API Committee on Refinery Environmental Control
CWA	Clean Water Act
DAF	Dissolved Air Flotation
DCS	Distributed Control System
EPCRA	Emergency Planning and Community Right-to-Know Act

EPA	U.S. Environmental Protection Agency
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
GC	Gas Chromatograph
gph	U.S. gallons per hour
gpm	U.S. gallons per minute
gr	Grain
HDF	Heavy Distillate Fuel
HVGO	Heavy Vacuum Gas Oil
ISBL	Inside Battery Limits
KW	Kilowatt
LAER	Lowest Achievable Emission Rate
LDAR	Leak Detection and Repair
LVGO	Light Vacuum Gas Oil
MACT	Maximum Achievable Control Technology
MDO	Maintenance Drain Out
Mg	Megagram, or metric ton
MMBTU	Million BTU
mmHgabs	Millimeters of mercury absolute, unit of pressure
MMscf	Million standard cubic feet
n/a	Not applicable or not available
NESHAP	National Emission Standard for Hazardous Air Pollutant
NH3	Ammonia

NO_X	Oxides of Nitrogen
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
OCPSF	Organic Chemicals, Plastics, and Synthetic Fibers
O&G	Oil & Grease
OSBL	Outside Battery Limits
OWS	Oily Water Sewer
P&ID	Piping & Instrumentation Diagram
PFD	Process Flow Diagram
POTW	Publicly Owned Treatment Works
PPA	Pollution Prevention Act
ppd	Pounds per day
ppm(w)	Parts per million (by weight)
PPTF	API Pollution Prevention Task Force
PSD	Prevention of Significant Deterioration
PSES	Pretreatment Standards for Existing Sources
PSNS	Pretreatment Standards for New Sources
RCRA	Resource Conservation and Recovery Act
SARA	Superfund Amendments and Reauthorization Act
SCR	Selective Catalytic Reduction
SOCMI	Synthetic Organic Chemical Manufacturing Industry
SO_X	Oxides of Sulfur
TAB	Total Annual Benzene Quantity

TBP	True Boiling Point
TDS	Total Dissolved Solids
TIC	Total Installed Cost
TOC	Total Organic Carbon
TRI	Toxics Release Inventory
TSD	Treatment, Storage, and Disposal
TSP	Total Suspended Particulates
TSS	Total Suspended Solids
t/y	U.S. tons/year
VOC	Volatile Organic Compound(s)
WWTP	Wastewater Treatment Plant

APPENDIX M:

Bibliography

Appendix M: BIBLIOGRAPHY

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