

# **RADIAN** **CORPORATION**

ENERGY PENALTIES ASSOCIATED  
WITH ENVIRONMENTAL REGULATIONS  
IN PETROLEUM REFINING

VOLUME I: DISCUSSION

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VOLUME I: DISCUSSION

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## ABSTRACT

This study was completed to provide the Environmental Protection Agency with estimates of the energy penalties which result from compliance by the petroleum refining industry with federally enforceable environmental regulations. Energy consumption and production capacity for the industry are estimated for the baseline year of 1974. Projections of the energy consumption and production of the industry are reported for the years 1980 and 1985 by using growth estimate models. Energy penalties for the baseline year 1974, as well as 1980 and 1985, are presented in summary form in the Discussion Volume and in detail in the Appendices. The total penalties are compared with estimates of the potential energy savings at refineries due to conservation modifications. A general description of the petroleum refining industry is given in the Discussion Volume.

The overall report is presented in two volumes. Volume I, the Discussion, presents the objectives, the industry description, the energy penalty calculation methodology, and the results of the study. Volume II, the Appendices, presents the industry energy consumption, production capacity, regulatory scenarios, control strategies, and energy penalties for the three study years 1974, 1980, and 1985.

## TABLE OF CONTENTS

	<u>Page</u>
Abstract.....	i
List of Figures and Tables.....	vii
List of Abbreviations.....	viii
1.0 EXECUTIVE SUMMARY.....	1
1.1 Results.....	1
1.2 Conclusions.....	4
1.3 Recommendations.....	5
2.0 INTRODUCTION.....	6
3.0 INDUSTRY DESCRIPTION.....	8
3.1 Major Manufacturing Processes.....	8
3.1.1 Petroleum Separation Processes.....	8
3.1.1.1 Atmospheric Distillation...	10
3.1.1.2 Vacuum Distillation.....	11
3.1.1.3 Light Ends Recovery.....	11
3.1.2 Petroleum Conversion Processes.....	12
3.1.2.1 Catalytic Cracking.....	12
3.1.2.2 Hydrocracking.....	14
3.1.2.3 Thermal Cracking.....	14
3.1.2.4 Catalytic Reforming.....	15
3.1.2.5 Alkylation.....	17
3.1.2.6 Isomerization.....	17
3.1.2.7 Polymerization.....	18
3.1.3 Petroleum Treating Processes.....	18
3.1.3.1 Hydrotreating.....	18
3.1.3.2 Sweetening.....	19
3.1.3.3 Acid Gas Removal.....	20
3.1.3.4 Crude Desalting.....	20
3.1.3.5 Acid/Caustic Treatment.....	21
3.1.3.6 Solvent Treating.....	21
3.1.3.7 Deasphalting.....	22
3.1.3.8 Aromatics Extraction.....	22

## TABLE OF CONTENTS (Cont'd)

	<u>Page</u>
3.1.3.9 Dewaxing/Deoiling.....	23
3.1.3.10 Asphalt Blowing.....	23
3.1.4 Feedstock and Product Handling.....	24
3.1.4.1 Storage.....	24
3.1.4.2 Blending.....	24
3.1.4.3 Loading and Unloading.....	25
3.1.5 Auxiliary Facilities.....	25
3.1.5.1 Sour Water Strippers.....	25
3.1.5.2 Wastewater Treatment Plant.....	26
3.1.5.3 Cooling Towers.....	27
3.1.5.4 Utilities Plant.....	27
3.1.5.5 Sulfur Recovery Plant.....	28
3.1.5.6 Hydrogen Plant.....	28
3.1.5.7 Blowdown System.....	29
3.1.5.8 Process Heaters.....	29
3.2 Typical Energy Requirements.....	30
3.3 Status and Geographic Distribution for Base Year.....	30
3.4 Prospects for Growth Through 1985.....	33
 4.0 INDUSTRY GROWTH PROJECTION METHODOLOGY.....	 35
4.1 Sector and Subsector Definitions.....	35
4.2 Sources of Data.....	35
4.3 Industry Growth Models.....	36
4.4 Major Assumptions.....	44
4.5 Caveats and Limitations.....	45
 5.0 BASELINE ENERGY CONSUMPTION METHODOLOGY.....	 47
5.1 Calculation of Process Requirements.....	47

## TABLE OF CONTENTS (Cont'd)

	<u>Page</u>
5.2 Allocation Among Fuel Types.....	49
5.3 Regionalization.....	50
5.4 Projected Changes Through 1985.....	50
5.5 Caveats and Limitations.....	51
 6.0 ENERGY PENALTY METHODOLOGY.....	 53
6.1 Identification of Major Environmental Regulations and Standards.....	53
6.1.1 Particulate Regulations.....	54
6.1.2 Sulfur Dioxide Regulations.....	55
6.1.3 Nitrogen Oxides Regulation.....	56
6.1.4 Carbon Monoxide Regulations.....	57
6.1.5 Hydrocarbon Regulations.....	58
6.1.6 Lead Regulations.....	59
6.1.7 Water Regulations.....	60
6.2 Control Strategies.....	61
6.2.1 Particulates.....	61
6.2.2 Sulfur Dioxide.....	68
6.2.3 Nitrogen Oxides Control Strategies...	70
6.2.4 Hydrocarbon Control Strategies.....	71
6.2.5 Lead Control Strategies.....	73
6.2.6 Water Control Strategies.....	77
6.3 Engineering Calculation Methodology.....	78
6.3.1 Particulates.....	78
6.3.2 Sulfur Dioxide.....	79
6.3.3 NO <sub>x</sub> - Engineering Calculation Methodology.....	82
6.3.4 Hydrocarbon-Engineering Calculation Methodology.....	83
6.3.5 Lead-Engineering Calculation Methodology.....	84

## TABLE OF CONTENTS (Cont'd)

	<u>Page</u>
6.3.6 Water-Engineering Calculation Methodology.....	92
6.4 Regionalization.....	95
6.5 Allocation Among Fuel Types.....	95
7.0 SUMMARY OF RESULTS.....	97
7.1 Minimum Energy Penalty Case.....	97
7.2 Maximum Energy Penalty Case.....	99
7.3 Most Likely Energy Penalty Case.....	99
8.0 SECONDARY IMPACT INDICATORS.....	100
8.1 Particulate Secondary Impact Indicators....	103
8.2 Sulfur Dioxide Secondary Impact Indicators.	104
8.3 NO <sub>x</sub> Secondary Impact Indicators.....	105
8.4 Hydrocarbon Secondary Impact Indicators....	105
8.5 Lead Secondary Impact Indicators.....	106
8.6 Water Secondary Impact Indicators.....	107
9.0 DISCUSSION.....	108
9.1 Possible Changes in the Refining Industry Makeup.....	108
9.2 Possible Changes in Environmental Regulations.....	109
9.3 Possible Changes in Control Methods.....	110
9.3.1 Particulates Control Changes.....	111
9.3.2 SO <sub>2</sub> Control Changes.....	111
9.3.3 NO <sub>x</sub> Control Changes.....	111
9.3.4 Hydrocarbon Control Changes.....	112
9.3.5 Lead Control Changes.....	112
9.3.6 Water Control Changes.....	112

TABLE OF CONTENTS (Cont'd)

	<u>Page</u>
10.0 CONCLUSIONS AND RECOMMENDATIONS.....	113
10.1 Conclusions.....	113
10.2 Refinery Conservation Opportunities.....	114
10.3 Recommendations.....	115
BIBLIOGRAPHY.....	117



## LIST OF FIGURES

<u>Number</u>		<u>Page</u>
3.1-1	Schematic of a Typical Integrated Petroleum Refinery.....	9
6.2-1	Reformer Yield/Severity Relationship.....	75
6.3-1	Gasoline Consumption by Grades.....	93

## LIST OF TABLES

3.2-1	Typical Energy Requirements of Basic Processes..	31
3.3-1	Summary of the 10 Largest Refineries.....	32
4.2-1	Announced Refining Expansion Plans, 1976.....	37
4.3-1	Summary of Crude Oil Demand Projections.....	42
5.1-1	Baseline Energy Consumption.....	48
6.2-1	Summary of Control Strategies.....	62
6.3-1	Typical Energy Requirements for Pollution Control Equipment.....	80
6.3-2	A. D. L.'s L. P. Model Results - Processing and Variable Outputs.....	86
6.3-3	A. D. L.'s L. P. Model Results - Gasoline Blending.....	87
6.3-4	Utility Requirements.....	90
7.1-1	Minimum Energy Penalties.....	98
7.2-1	Maximum Energy Penalties for 1980 and 1985.....	100
7.3-1	Most Likely Energy Penalties for 1980 and 1985..	101
8.2-1	Chemical and Catalyst Requirements for SO <sub>2</sub> Control.....	105
10.2-1	Example Refinery Energy Consumption Breakdown...	114

## LIST OF ABBREVIATIONS

AQCR - Air Quality Control Region  
bbl - barrel  
BOM - Bureau of Mines  
BOD - biological oxygen demand  
BPD - barrels per day  
 $C_1$  - methane  
 $C_2$  - ethane  
 $C_2^=$  - ethylene  
 $C_3$  - propane  
 $C_3^=$  - propylene  
 $iC_4$  - normal butane  
 $C_4^=$  - butylene  
 $C_5^+$  - light naphtha  
cc - cubic centimeter  
CD - calendar day  
COB - carbon monoxide boiler  
CRU - catalytic reformer unit  
DFA - direct flame afterburner  
dscf - dry standard cubic foot  
ESP - electrostatic precipitator  
FCCU - fluid (fluidized-bed) catalytic cracking unit  
FEA - Federal Energy Administration  
HDS - hydrodesulfurization  
Heavy S.R. Gasoline - heavy straight run gasoline

LIST OF ABBREVIATIONS (Cont'd)

HTR - high temperature regeneration  
Light S.R. Gasoline - light straight run gasoline  
LP - linear programming  
LPG - liquefied petroleum gas  
LV% - liquid volume percent  
M - thousand  
MIC - multiple internal cyclones  
MM - million  
MMT - methylcyclopentadienyl manganese tricarbonyl  
NSPS - New Source Performance Standards  
P - process weight  
PAD - Petroleum Administration for Defense  
ppm - parts per million (parts)  
psia - pounds per square inch absolute  
psig - pounds per square inch gauge  
RACT - reasonable available control technology  
RON - research octane number  
scf - standard cubic feet  
scfm - standard cubic feet per minute  
SIP - State Implementation Plan  
TCC - moving-bed catalytic cracking  
USG - U.S. gallon  
 $\mu$  - micron

## 1.0 EXECUTIVE SUMMARY

This report is one part of a larger study to examine the energy penalties which result from environmental regulations applicable to selected industries. The particular industry examined in this report is petroleum refining. This section summarizes the results of the refining industry study and presents the conclusions which were drawn from these results. Also, recommendations for areas of further work are listed.

### 1.1 Results

The results presented in this section are based on the data given in Appendix B. The data in Appendix B were obtained from calculations based on information which came primarily from articles, journals, government publications, and published reports. Since the exact regulatory atmosphere for the years 1980 and 1985 is unknown, the results for these years are presented in three cases. The minimum, maximum, and most likely energy penalties for each of these years are calculated. This shows the relative impact of regulatory stringency on the energy penalties. The results of this report are listed below:

- The 1974 average baseline energy consumption for the petroleum refining industry was  $8.16 \times 10^{12}$  Btu<sup>1</sup> per day or approximately 669,000 Btu per barrel of crude charged.

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<sup>1</sup>A table of conversion factors for English to metric units is presented following Section 10.0.

- The 1974 energy penalty due to environmental regulations, excluding CO controls, was  $0.11 \times 10^{12}$  Btu per day or approximately 9000 Btu per barrel of crude charged. This represents about 1.3 percent of the energy required to process a barrel of crude. CO controls were excluded because they were not required by regulation in 1974.
- The 1980 average baseline energy consumption for refining is projected to be  $1.16 \times 10^{12}$  Btu per day or 636,000 Btu per barrel of crude charged.
- The 1980 minimum energy penalty due to environmental regulations is estimated to be  $0.51 \times 10^{12}$  Btu per day or about 27,800 Btu per barrel of crude charged. This represents about 4.4 percent of the energy required to process a barrel of crude oil.
- The 1980 maximum energy penalty due to environmental regulations is estimated to be  $1.63 \times 10^{12}$  Btu per day or about 89,200 Btu per barrel of crude charged. This represents about 14.0 percent of the energy required to process a barrel of crude oil.

- The 1980 "most likely" energy penalty due to environmental regulations is estimated to be  $0.89 \times 10^{12}$  Btu per day or about 48,600 Btu per barrel of crude charged. This is equal to about 7.6 percent of the energy needed to refine a barrel of crude oil.
- The 1985 minimum energy penalty due to environmental regulations is estimated to be  $0.75 \times 10^{12}$  Btu per day or about 33,800 Btu per barrel of crude charged. This is equal to about 5.5 percent of the energy used to refine a barrel of crude oil.
- The 1985 maximum energy penalty due to environmental regulations is estimated to be  $2.25 \times 10^{12}$  Btu per day or about 101,200 Btu per barrel of crude charged. This is equal to approximately 16.8 percent of the energy used to refine a barrel of crude oil.
- The 1985 "most likely" energy penalty due to environmental regulations is estimated to be  $1.33 \times 10^{12}$  Btu per day or about 44,300 Btu per barrel of crude charged. This is equal to about 9.9 percent of the energy needed to refine a barrel of crude oil.

## 1.2 Conclusions

Some conclusions which may be drawn based upon the results of this study are:

- For 1980 the largest contributors to the total "most likely" energy penalty are SO<sub>2</sub> control and gasoline lead reduction. They contribute 42 percent and 41 percent of the total, respectively.
- For 1985 the largest contributors to the total "most likely" energy penalty are SO<sub>2</sub> control and gasoline lead reduction, again. They contribute 37 percent and 50 percent of the total, respectively.
- Regulatory stringency has a significant effect on the energy penalties for the petroleum refining industry. The maximum case total energy penalties for 1980 and 1985 are about 3 times larger than the minimum case penalties for the same years.
- The reported energy conservation potential for the petroleum refining industry for 1980 and 1985 is roughly equivalent to the "most likely" energy penalties estimated for the refining industry for 1980 and 1985.

### 1.3      Recommendations

It is recommended that further work be done in the area of obtaining more accurate information on existing and projected pollution control equipment for the petroleum refining industry. The primary sources of information for this report were articles, journals, and reports published by governmental agencies and the refining industry. The accuracy of the results of this study could be improved if a survey were completed of the petroleum refining industry's current and projected pollution abatement inventory.



Regulations issued by federal and local governments and other empowered authorities pursuant to the Clean Air Act and the Federal Water Pollution Control Act have impacted many industries. This report is one part of a larger study to examine the energy requirements or penalties resulting from compliance by specific industries with these federally enforceable environmental regulations. This penalty is defined as the incremental demand for energy above a baseline demand that would occur in the absence of any federally enforceable environmental regulations. The study encompasses the 1974-1985 time frame with outputs provided for the years 1974, 1980, and 1985. The petroleum refining industry is examined in this report and the methodology for calculating the energy penalties as well as the results of the calculations are presented in this volume.

The methodology used to calculate the energy penalties for the chosen years involved three phases. The objective of the first phase was to project the growth in capacity for the refining industry from 1974 to 1985. The objective of the second phase was to establish the refining industry energy consumption for the chosen baseline year of 1974. The objective of the third phase was to calculate the energy penalties for the refining industry for the years 1974, 1980, and 1985.

Documentation of the refining industry growth projection is presented in Section 4.0. The total estimated capacity for the industry for 1980 and 1985 is given as well as the geographical distribution and the size of each expansion. The models and major assumptions used in making the projections are also discussed. The resulting projections provide a basis from which the 1980 and 1985 energy penalties are calculated.

The methodology used to determine the refining industry energy consumption for the baseline year of 1974 is presented in Section 5.0. The energy requirements are organized by census region and expressed according to the types of fuels actually used. The energy consumption due to existing environmental controls is estimated and the baseline consumption numbers adjusted to determine a true baseline "no environmental controls" energy requirement.

Section 6.0 describes the methodology used to estimate the energy penalties for the industry for the years 1980 and 1985. The environmental regulations which impact the refining industry are analyzed first. Then the various environmental control strategies available to the industry to achieve compliance with the regulations are reviewed. Finally, the calculations which were used to estimate the energy penalties for each census region and year are described. Section 7.0 presents a summary of the results of the energy penalty calculations.

In addition to calculating the energy penalties, secondary impact indicators were also specified. Secondary impact indicators are defined as the control equipment used and the materials consumed during the operation of a control system. Section 8.0 describes how these indicators were determined for the study.

Section 3.0 presents a general description of the petroleum refining industry. It is intended to serve as background information for the study.

### 3.0 INDUSTRY DESCRIPTION

#### 3.1 Major Manufacturing Processes

The petroleum refining industry is primarily involved in the conversion of crude oil into more than 2500 refined products including liquified petroleum gas, gasoline, kerosene, aviation fuel, diesel fuel, fuel oils, lubricating oils, and feedstocks for the petrochemical industry. Petroleum refinery activities start with crude storage at the refinery, include all petroleum handling and refining operations, and terminate with storage of the refined products at the refinery.

The petroleum refining industry employs a wide variety of processes for the conversion of crude oil to finished petroleum products. A refinery's processing flow scheme selection is largely determined by the composition of the crude oil feedstock and the chosen slate of petroleum products. The example refinery flow scheme presented in Figure 3.1-1 shows the general processing arrangement used by U.S. refineries for major refinery processes. The arrangement of these processes will vary among refineries and few, if any, refineries employ all of these processes.

In general, refinery processes and operations can be divided into five categories: separation processes, conversion processes, treating processes, product handling, and auxiliary facilities. The processes comprising each of these categories are presented in the following sections.

##### 3.1.1 Petroleum Separation Processes

The first phase in petroleum refining operations is the separation of crude oil into its major constituents using

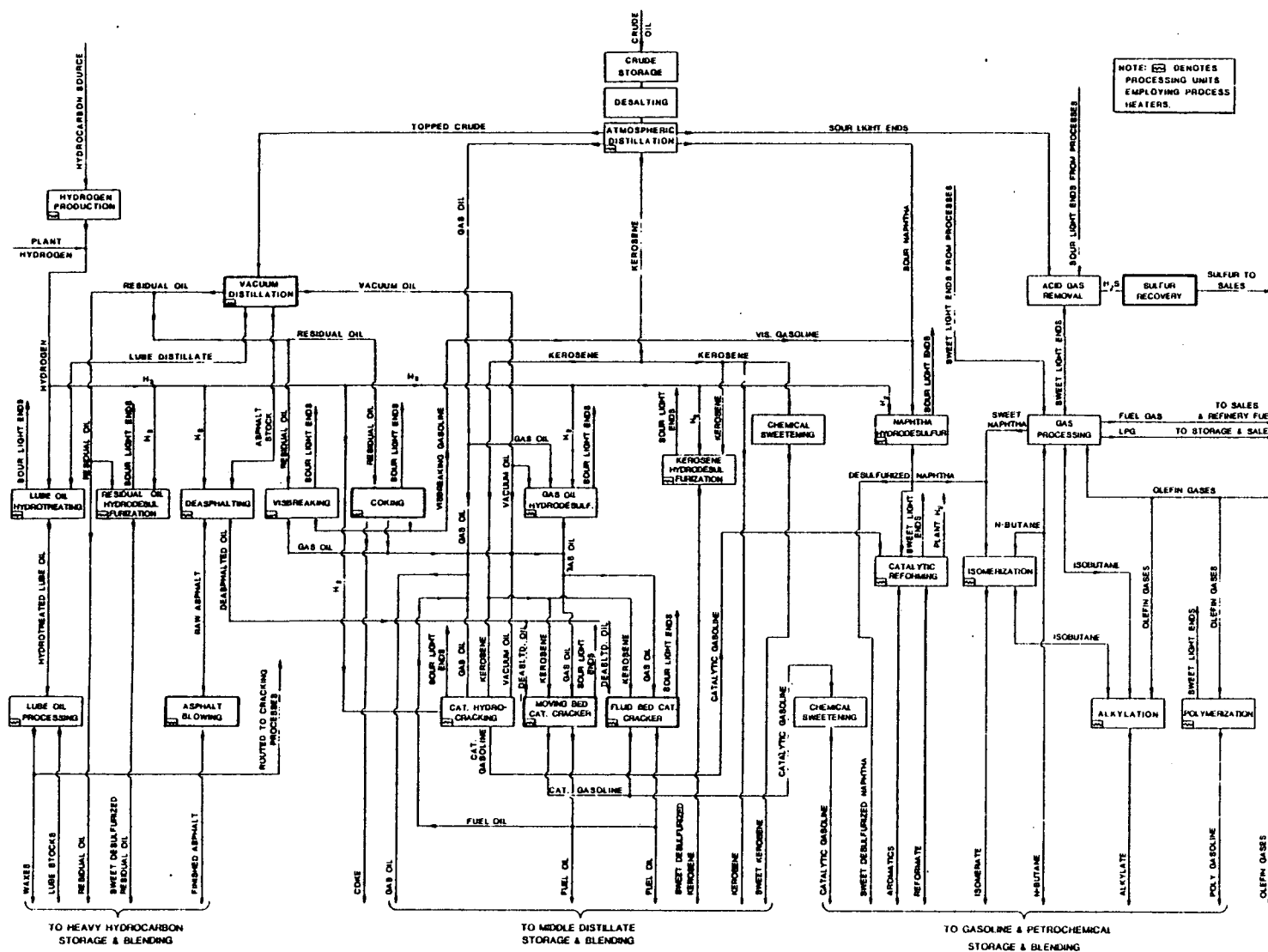


Figure 3.1-1. Schematic of a Typical Integrated Petroleum Refinery

three petroleum separation processes: atmospheric distillation, vacuum distillation, and light ends recovery. Crude oil consists of a mixture of hydrocarbon compounds including paraffinic, naphthenic, and aromatic hydrocarbons plus small amounts of impurities including sulfur, nitrogen, oxygen, and metals. Refinery separation processes use distillation, stripping, and absorption to separate these crude oil constituents into common boiling point fractions.

#### 3.1.1.1 Atmospheric Distillation

The atmospheric distillation process is used to separate crude oil into a light ends fraction, several intermediate boiling fractions, and a topped crude fraction. The light ends fraction contains a wide range of low boiling components which are separated further in the light ends recovery process. The topped crude fraction contains a wide range of high boiling components which are separated further in the vacuum distillation process.

Crude oil entering the atmospheric distillation unit is heated in a process heater, often termed a pipe still, to temperatures of 650°F to 750°F. The heated crude oil is flashed into a multi-tray distillation column operating in the pressure range of 10 psig. In the distillation column the crude oil components are separated by vaporization and condensation into common boiling point fractions. To aid the separation efficiency of the column, stripping steam is normally injected into the bottom of the column and side stream fractions are passed through side stream steam strippers. Occasionally, reboilers are used instead of steam strippers. Standard petroleum fractions withdrawn from the atmospheric distillation column include light ends, naphtha, kerosene, gas oil, and topped crude. These side

streams are withdrawn from the distillation column at temperatures ranging from 200°F to 800°F.

#### 3.1.1.2 Vacuum Distillation

Topped crude withdrawn from the bottom of the atmospheric distillation column is composed of high boiling point hydrocarbons which may crack and polymerize before evaporating at atmospheric pressures. In order to further separate topped crude into components, it must be distilled in a vacuum distillation column at a very low pressure and in a steam atmosphere.

In the vacuum distillation unit topped crude is heated with a process heater to temperatures ranging from 700°F to 800°F. The heated topped crude is flashed into a multi-tray vacuum distillation column operating at a vacuum of 0.5 psia to 2 psia. In the vacuum column the topped crude is separated into common boiling point fractions by vaporization and condensation. Stripping steam is normally injected into the bottom of the vacuum distillation column to assist in the separation by lowering the effective partial pressures of the components. Standard petroleum fractions withdrawn from the vacuum distillation column include lube distillates, vacuum gas oils, asphalt stocks, and residual oils. The vacuum in the vacuum distillation column is normally maintained by the use of steam ejectors and barometric or surface condensers, but may be maintained by the use of vacuum pumps.

#### 3.1.1.3 Light Ends Recovery

Refinery gas streams from the atmospheric distillation unit and those streams produced as by-products in many other processing units are separated into major components in a light ends recovery unit.

Gas separation in the light ends recovery unit is generally accomplished by a combination of absorption and/or distillation processes. The degree of separation required dictates the processes used. Gross separations might include three major cuts: fuel gas ( $C_1$ ,  $C_2$ ,  $C_3$ ), LPG ( $C_3$ ,  $C_4$ ), and light naphtha ( $C_5+$ ). Refined separations are becoming more common and may involve separation of the light ends into individual hydrocarbon species:  $C_1$ ,  $C_2$ ,  $C_2^=$  (ethylene),  $C_3$ ,  $C_3^=$  (propylene),  $iC_4$  (isobutane),  $C_4^=$  (butylene),  $C_5+$ . The temperatures normally used in light ends processing range from cryogenic to moderate and the pressures normally used range from atmospheric to 400 psia.

### 3.1.2 Petroleum Conversion Processes

Product demand and economic considerations require that less valuable components of crude oil be converted to more valuable products by cracking, reforming and alkylation processes. To meet the demands for high octane gasoline, jet fuel, and diesel fuel, the surplus residual and fuel oil components of a barrel of crude oil can be converted economically to gasoline and lighter fractions, maximizing refinery profits. In addition, waste disposal is very expensive and all components of crude oil must be converted to salable products.

#### 3.1.2.1 Catalytic Cracking

Catalytic cracking, using heat, pressure, and catalysts, converts heavy oils into lighter products with product distributions favoring the more valuable gasoline and distillate blending components. Feedstocks are usually gas oils from atmospheric and vacuum distillations, coking and deasphalting. They typically have a boiling range of 400°F to 1000°F. All of the catalytic cracking processes in use today can be classified as fluidized-bed or moving-bed units, except for hydrocracking, which is discussed in the next section.

- Fluidized-bed Catalytic Cracking (FCC) - The FCC process, catalyst beads ( $\sim 0.5$  cm) flow by gravity into the top act as a fluid when aerated with a vapor. Fresh feed is pre-heated in a process heater, and introduced into the bottom of a vertical transfer line or riser, with hot regenerated catalyst. The hot catalyst vaporizes the feed bringing it to the desired reaction temperature ( $880^{\circ}\text{F}$  to  $980^{\circ}\text{F}$ ). The high activity of modern catalysts causes most of the cracking reactions to take place in the riser as the catalyst and oil mixture flow upward into the reactor. The hydrocarbon vapors are separated from the catalyst particles by cyclones in the reactor. The reaction products are sent to a fractionator for separation.

The spent catalyst falls to the bottom of the reactor and is steam stripped as it exits the reactor to remove adsorbed hydrocarbons. In the regenerator coke deposited on the catalyst as a result of the cracking reactions is burned off in a controlled combustion process with preheated air. Regenerator temperature is usually  $1100^{\circ}\text{F}$  to  $1250^{\circ}\text{F}$ . The catalyst is then recycled to be mixed with fresh hydrocarbon feed.

- Moving-bed Catalytic Cracking (TCC) - In the TCC process, catalyst beads ( $\sim 0.5$  cm) flow by gravity into the top of the reactor where they contact a mixed phase hydrocarbon feed. Cracking reactions take place as the catalyst and hydrocarbons move concurrently downward through the reactor to a zone where the catalyst is separated from the vapors. The gaseous reaction products flow out of the reactor to the fractionation section. The catalyst is steam stripped to remove any absorbed hydrocarbons. It then falls into the regenerator where coke is burned from the catalyst with air. The regenerated catalyst is separated from the flue gases and pneumatically or mechanically recycled to be mixed with fresh hydrocarbon feed. The operating temperatures of the reactor and regenerator in the TCC process are comparable to those in the FCC process.



#### 3.1.2.2 Hydrocracking

Hydrocracking catalytically converts heavy feedstocks into lighter saturated hydrocarbon fractions through cracking and hydrogenation under severe conditions (500°F to 950°F, 1000 to 2000 psig) in the presence of hydrogen. Hydrocracking is generally a supplementary process to catalytic cracking and can crack heavier feedstocks such as cycle oils and coker distillates. In addition, residual fuel oils and reduced crudes can be hydrocracked but require a different technology.

In a typical two-stage system fresh feed is mixed with recycle and make-up hydrogen and preheated in a process heater before entering the first of two fixed-bed reactors. The hydrotreated and partially hydrocracked reactor effluent goes through heat exchangers to a high pressure separator where hydrogen-rich gas is flashed and recycled. The liquid effluent goes to a low pressure separator where part of the light ends are removed, and then to a fractionator where gasoline and lighter products are taken overhead. The bottoms stream is mixed with hydrogen recycle, reheated, and sent to the second reactor. The second reactor product is sent through separators and combined with the liquid effluent from the first reactor as feed to the fractionator.

#### 3.1.2.3 Thermal Cracking

Visbreaking and Coking are thermal cracking processes which break heavy oil molecules by exposing them to high temperatures.

• Visbreaking - Topped crude or vacuum residuals are thermally cracked under mild conditions (850°F to 900°F, 50 to

250 psig) in the visbreaker furnace, reducing the viscosity or pour point of the charge. The feed is heated and thermally cracked in the visbreaker furnace. The cracked products are quenched with gas oil and flashed into a fractionator. The vapor overhead is separated into light distillate products. A heavy distillate recovered from the liquid can be used as a fuel oil blending component or used as catalytic cracking feed. The residue is usually used as coker feed.

- Coking - Coking is a thermal cracking process which is used to minimize yields of residual fuel oil. Vacuum residuals and thermal tars are cracked at high temperature and low pressure. Products are coke, gas oils and lighter petroleum stocks.

In the delayed coking process, heated charge stock is fed into the bottom section of a fractionator where light ends are stripped from the feed. The remaining feed is combined with recycle from the coke drum and is rapidly heated in the coking heater to a temperature of 900°F to 1100°F.

Steam injection is used to control heater velocities. The vapor-liquid leaves the heater, passing to a coke drum where, with controlled residence time, pressure (25 to 30 psig), and temperature (750°F), coke is formed. Vapors from the top of the drum return to the fractionator where the thermal cracking products are recovered.

#### 3.1.2.4 Catalytic Reforming

Catalytic reforming converts low octane naphthas into high octane gasoline blending components through isomerization,

cyclization, and dehydrogenation. The feedstock normally includes heavy, straight-run gasolines and naphthas with a typical boiling range of 180°F to 375°F.

Reforming processes are continuous, cyclic or semi-regenerative depending upon the frequency of catalyst regeneration.

- In the continuous process small amounts of catalyst are continuously removed from the moving bed reactor and regenerated in a separate unit that maintains high catalyst activities.
- The cyclic process employs fixed-bed reactors and is characterized by having one reactor in addition to those on-stream. When catalyst activity in a reactor drops below the desired level, it is replaced by the extra reactor and regenerated without interruption of the process.
- The semi-regenerative process employs fixed-bed reactors which operate continuously until the catalyst activity level is unacceptable. No extra reactor is present and thus regeneration requires process interruption. The unit is taken off-stream, blocked out, and the catalyst is regenerated in situ.

In a typical reforming process the feedstock and recycle hydrogen mixture are preheated to reaction temperature (900°F) by a combination of heat exchangers and a furnace. Hydrogen is present to inhibit coke formation on the catalyst. The reaction pressure is 100-450 psig. The preheated reactants

enter a series of alternate reactors and furnaces. The furnaces are necessary to reheat the reactor products after the highly endothermic dehydrogenation reactions. Usually three reactors are sufficient and the effluent from the final reactor is cooled to condense liquid products. Hydrogen-rich gases are separated from the liquid in a separator, and the liquid is fractionated to remove light ends. Hydrogen formed in the operation is separated from the gas stream, recycled to the reactors, and the excess diverted to a hydrogen collection system.

#### 3.1.2.5 Alkylation

Alkylation units produce a high octane component for gasoline blending by catalytically reacting low molecular weight olefins (e.g., ethylene, propylene, butylene, pentylene) with isoparaffins (usually isobutane). High purity sulfuric or hydrofluoric acid catalyzes the liquid phase reaction.

Dehydrated olefinic feed is mixed with excess isobutane and then contacted with the liquid catalyst in the reactor. Isobutane is added in excess to increase the octane number and yield and to reduce side reactions and acid consumption. The reaction products are separated into hydrocarbon and acid phases in a settler. Acid is returned to the reactor, and the alkylate is processed further by chemical treatment and distillation. Alkylate is separated from the excess isobutane and from normal butane and propane. Isobutane is returned to the reactor, while propane and butane are removed from the process.

#### 3.1.2.6 Isomerization

Catalytic isomerization processes are used to increase the octane rating of light, straight-run gasoline or to produce alkylation feedstocks from normal butane by catalytically converting the normal paraffins to their isomers.

The dehydrated and desulfurized feedstock is mixed with hydrogen and an organic chloride promoter. The mixture is then heated in a process heater to reaction temperature (500°F). Isomerization occurs in one or two fixed-bed reactors operating at pressures of 300 to 400 psig. A hydrogen atmosphere is used to minimize carbon deposits on the catalyst. The effluent is cooled and charged to a separator where hydrogen-rich gas is flashed and recycled. The liquid is then stabilized by removing light ends and separated into normal and isoparaffin fractions. The normal paraffins are generally recycled to the reactor while the isoparaffins are sent to alkylation (isobutane) and gasoline blending (isopentane, isohexane).

#### 3.1.2.7 Polymerization

The polymerization unit produces a high octane component for gasoline blending or for a petrochemical feedstock by reacting two olefinic gases in the presence of a catalyst (usually phosphoric acid). The feed can be any combination of olefinic gases and is commonly a product of gas processing units within the refinery.

#### 3.1.3 Petroleum Treating Processes

Petroleum treating processes stabilize products, separate fractions for further processing, and remove objectionable elements from petroleum products and feedstocks. Stabilization is the conversion of olefins and diolefins to saturated hydrocarbons. Objectionable elements removed include sulfur, nitrogen, oxygen, halides and metals. Separation processes include aromatics extraction, deasphalting, dewaxing and deoiling.

##### 3.1.3.1 Hydrotreating

The hydrotreating process catalytically stabilizes petroleum products and removes objectionable elements from

products and feedstocks by reacting them with hydrogen. Feedstocks range from naphtha to reduced crude. Operating conditions also vary widely with pressures ranging from 100 to 300 psig and reactor temperatures of 500°F to 800°F.

Oil feed is mixed with hydrogen-rich gases and heated to the desired reactor inlet temperature. The temperature is usually kept below 800°F to minimize cracking. Oil feed and hydrogen enter the top of a fixed-bed reactor where they react over a metal oxide catalyst to form hydrogen sulfide, ammonia, saturated hydrocarbons and free metals. The effluent is cooled and the oil is separated from the hydrogen-rich gases. The oil is then stripped of any remaining hydrogen sulfide and light ends. The effluent gas is treated to remove hydrogen sulfide and recycled to the reactor. The free metals remain on the catalyst.

#### 3.1.3.2 Sweetening

Sweetening of distillates is accomplished by the conversion of the sulfur containing compounds to alkyl-disulfides in the presence of a catalyst. The conversion process may be followed by an extraction.

In one conversion process sulfur is added to the sour distillate with a small amount of caustic and air. This mixture is then passed upward through a fixed-bed catalytic reactor countercurrent to a flow of caustic entering at the top of the vessel. There are numerous sweetening techniques available to refiners.

In one conversion and extraction process the sour distillate is prewashed with caustic and then contacted with a solution of catalyst and caustic in the extractor. The extracted

distillate is sweetened by reacting with air, allowed to settle and sent to inhibiting and storage. Regeneration is accomplished by mixing caustic from the bottom of the extractor with air and separating the disulfides and excess air.

#### 3.1.3.3 Acid Gas Removal

Hydrogen sulfide is formed as a result of the conversion of sulfur compounds in hydrotreating, cracking and coking operations and is also present to some extent in solution in crude oils. The acid gas removal unit removes hydrogen sulfide from refinery gases by absorption and reaction with some regenerable sorbent.

There are many processes for acid gas removal, but the diethanolamine process has been most widely used. An aqueous fifteen to thirty percent diethanolamine solution is introduced into the top of an absorber in which it flows countercurrently to the refinery gas flow, selectively absorbing hydrogen sulfide and  $\text{CO}_2$ . The rich solution then flows into a flash tank allowing any entrained or dissolved methane and ethane to be separated. The solution is preheated, and the acid gases are stripped from the solution with steam in the regenerator. The steam is condensed, and the acid gases are sent to a sulfur recovery unit.

#### 3.1.3.4 Crude Desalting

Crude desalting is usually the first processing step in a refinery. It removes inorganic salts, water, silt and water soluble compounds from the raw crude to prevent equipment fouling, corrosion and catalyst poisoning in downstream units.

Water and crude are thoroughly mixed and heated. The mixture is then demulsified. Soluble impurities are separated

from the crude by absorption into the water phase. Phase separation is accomplished by physical decanting and electrostatic coalescing. Surface active chemicals are sometimes added to hasten the separation.

#### 3.1.3.5 Acid/Caustic Treatment

Hydrocarbon streams are treated with acid to remove aromatics, attack olefins, and dissolve resinous or asphaltic substances and nitrogen bases. Caustic treatment is used to remove trace sulfur compounds and is often used following acid treatment for neutralization.

The hydrocarbon stream is contacted with the treating agent and mixed thoroughly to form an emulsion. The emulsion is then broken and separated into two phases by coalescence, sometimes aided by electrostatic precipitation. The product is a treated, stable hydrocarbon stream.

#### 3.1.3.6 Solvent Treating

Solvent treating processes are applied primarily to the extraction of undesirable components from lubricating oils. They are also used to separate petroleum fractions and to remove impurities from gas oils. Undesirable components removed include unstable, acidic, organometallic, nitrogen and sulfur compounds.

Solvent and oil are contacted in a countercurrent continuous extractor. The raffinate and extract streams are steam-stripped to produce refined oil and finished extract streams. The solvent is separated from the oil and water by settling or stripping and returned to the contactor.



#### 3.1.3.7 Deasphalting

The deasphalting process separates asphaltic materials from heavy oil and residual fractions, recovering any oil for use as a feed to catalytic cracking processes and producing a few asphaltic material.

Vacuum residuals and a mixture of liquid propane and other light hydrocarbons are pumped to an extraction tower where a separation based on solubility difference takes place. A deasphalted oil solution and an asphalt solution are the products. These solutions are further processed through evaporation and steam stripping to produce the final oil and asphalt products and to recovery the propane solvent.

#### 3.1.3.8 Aromatics Extraction

An aromatics extraction unit produces a high octane gasoline blending component by liquid-liquid extraction of aromatics from typical refinery feedstocks.

Fresh feed is charged to a contactor (extractor) for countercurrent extraction of the aromatic components with a solvent. The low aromatic raffinate is discharged from the top of the column and water washed. The rich solvent is charged to an extractive stripper where the hydrocarbon overhead is returned as reflux to the extractor. The bottoms are charged to the recovery column where a solvent-free aromatic extract is separated. The lean solvent is returned to the extractor. In many units the extractive stripper and the recovery column are combined. In this case, the high purity aromatics are withdrawn as a side-stream and made solvent-free by water washing.

#### 3.1.3.9 Dewaxing/Deoiling

Dewaxing/Deoiling units separate waxy materials from various lube oil fractions to produce low pour point lubricating oils and wax.

The oil and solvent are mixed and chilled at a controlled rate. The resulting wax crystals are separated from the oil and solvent by rotary drum filtration. The wax is then washed and sent to a solvent recovery system. The oil and solvent filtrate is sent to a similar solvent recovery system. It may consist of evaporators or of high and low pressure flashes, depending on the solvent used. The evaporation or flashing steps are followed by steam stripping.

#### 3.1.3.10 Asphalt Blowing

The asphalt blowing process oxidizes asphaltic residual oils, increasing their melting temperature and hardness to achieve an increased resistance to weathering.

The oils containing a large quantity of polycyclic aromatic compounds (asphaltic oils) are oxidized by blowing heated air through a preheated batch mixture or, in the continuous process, by passing hot air countercurrent to the oil flow. The reaction is exothermic, and quench steam is sometimes needed for temperature control. In some cases ferric chloride or phosphorus pentoxide is used as a catalyst to increase the reaction rate and impart special characteristics to the asphalt. Blowing is stopped when the asphalt reaches the desired penetration specifications.

#### 3.1.4 Feedstock and Product Handling

The refinery feedstock and product handling operations consist of storage, blending, and unloading activities. All feedstocks entering the refinery and all products leaving the refinery are subject to the refinery handling operations.

##### 3.1.4.1 Storage

All refineries have a feedstock and product storage area, termed a "tank farm", which provides surge storage capacity to insure smooth, uninterrupted refinery operations. Individual storage tank capacities range from less than 1000 barrels to more than 250,000 barrels, and total tank farm storage capacities commonly range from several days to several weeks refinery supply. The most common types of storage tanks used by refineries include fixed roof tanks, floating roof tanks, internal floating roof tanks, variable vapor space tanks and pressure tanks. New source performance standards require that hydrocarbon liquids with true vapor pressures ranging from 1.5 to 11.1 psia be stored in floating roof tanks or equivalent vapor controls and that hydrocarbon liquids with true vapor pressures in excess of 11.1 psia be stored in storage tanks with vapor recovery systems or with equivalent vapor controls.

##### 3.1.4.2 Blending

Most fuel products from petroleum refineries are a selective blend of several refinery product streams mixed to yield specific fuel characteristics. Some of the characteristics affected by blending are volatility, octane rating, cetane rating, flash point, sulfur level, pour point, and ash content. Typical blended fuels include gasoline, diesel oil, kerosene, distillate fuel oils, and residual fuel oils.

The blending of refinery products is performed by mixing products from various product storage tanks in a blending manifold. After blending, the fuels may either be stored in a blended product storage tank or put directly into pipelines.

#### 3.1.4.3 Loading and Unloading

Although most refinery feedstocks and products are transported by pipeline, many feedstocks and products are transported by trucks, rail cars, and marine vessels. The refinery feedstocks and products are transferred to and from these transport vehicles in the refinery tank farm area using specialized pumps and piping systems.

#### 3.1.5 Auxiliary Facilities

Auxiliary facilities include a wide assortment of processes and equipment which are not directly involved in the refining of crude oil, but which perform functions vital to the operation of the refinery. Products from auxiliary facilities (clean water, steam, process heat, etc.) are required by the majority of refinery process units and are not limited to any one part of the refinery.

##### 3.1.5.1 Sour Water Strippers

Sour water strippers remove hydrogen sulfide ( $H_2S$ ) and ammonia ( $NH_3$ ) from sour water condensate streams generated by such refinery processes as hydrotreating, hydrodesulfurization, tail gas treating, and catalytic cracking.

The feed streams going to sour water strippers are refinery condensates having  $H_2S$  concentrations up to 6,000 ppm,  $NH_3$  concentrations up to 4,000 ppm, and phenol concentrations up

to 600 ppm. If the  $H_2S$  and  $NH_3$  are to be removed as a single stream, the sour water is fed into a single stripping column which distills  $H_2S$ ,  $NH_3$ , and some phenols into the column overhead and discharges treated water from the column bottom. If the  $H_2S$  and  $NH_3$  are to be removed as separate streams, the sour water is fed into a series of stripping columns which separate  $H_2S$  and  $NH_3$  into individual product streams. The stripper columns may use either direct steam stripping or steam heated reboilers to accomplish the gas-liquid separation. A good combination stripper can have 99% removal of  $H_2S$  and about 90 to 93% of  $NH_3$ . The  $H_2S$  rich stream or  $H_2S$ - $NH_3$  rich stream is routed to the sulfur recovery plant. If an  $NH_3$  stream is produced, it is treated for trace  $H_2S$  removal and sold as high quality  $NH_3$ .

#### 3.1.5.2 Wastewater Treatment Plant

All refineries employ some form of wastewater treatment to upgrade the quality of water effluents such that they can be safely returned to the environment or reused within the refinery.

The design of wastewater treatment plants is complicated by the diversity of refinery pollutants including oil, phenols, sulfides, dissolved solids, suspended solids, toxic chemicals, and BOD-bearing materials. Although the wastewater treatment processes employed by refineries vary greatly, they generally include neutralizers, oil-water separators, settling chambers, clarifiers, dissolved air flotation systems, coagulators, aerated lagoons, and activated sludge ponds. Refinery water effluents are collected from various processing units and conveyed through sewers and ditches to the wastewater treatment plant. Most of the wastewater treatment processing occurs in open ponds and tanks.

#### 3.1.5.3 Cooling Towers

Cooling towers are used extensively in refinery cooling water systems to transfer heat from the cooling water to the atmosphere. The only refineries not employing cooling towers are those with once through cooling. The increasing scarcity of large water supplies required by once through cooling is contributing to the disappearance of that form of refinery cooling.

In the cooling tower warm cooling water returning from refinery processes is contacted with air by cascading through packing. Heat in the cooling water is transferred from the cooling water to the air by heat exchange and evaporation. Cooling water circulation rates for refineries commonly range from 0.3 to 3.0 gpm per BPD of refinery capacity.

#### 3.1.5.4 Utilities Plant

The utilities plant supplies the steam necessary for the refinery. The steam can be used to produce electricity by throttling through a turbine. It may also be used for heating by direct or indirect contact with hydrocarbon streams. The generated steam used in noncontact process heating releases its latent heat by condensation and returns to the boiler. The waste steam from noncontact process heating and power generation can be used in direct contact operations as a stripping medium or a process fluid. It may also be used to produce a vacuum, or to drive pumps and compressors.

Steam generators or boilers are usually designed to deliver steam above 600 psig. The steam is produced in tube bundles which surround the combustion chamber of the boiler. Heating of the tubes is accomplished by both radiation and convection. The fuel burned may be refinery gas, natural gas, residual fuel oil or a combination, depending on the economics, operating conditions and pollution requirements.

#### 3.1.5.5 Sulfur Recovery Plant

Sulfur recovery plants are used in petroleum refineries to convert hydrogen sulfide ( $\text{H}_2\text{S}$ ) produced in the acid gas treating unit into the more disposable by-product, elemental sulfur.

Although several other sulfur recovery processes are available, the primary process used by petroleum refineries is the modified Claus process. In the modified Claus process one-third of the  $\text{H}_2\text{S}$  in the acid gas feed is partially combusted in a furnace to  $\text{SO}_2$ . After passing through a waste heat boiler, the partially combusted acid gases pass through a series of two to four bauxite or alumina catalyst reactors where the  $\text{H}_2\text{S}$  and  $\text{SO}_2$  are reacted to produce elemental sulfur and water. Molten sulfur is collected after each reactor. After the last reactor, the remaining portion of the acid gas stream is normally either incinerated or treated in a tail gas treatment unit. In a typical, well designed, three reactor Claus unit, 95 to 98 percent of the  $\text{H}_2\text{S}$  in the feed gas is converted to elemental sulfur.

#### 3.1.5.6 Hydrogen Plant

In many refineries the catalytic reforming operation supplies the hydrogen necessary for hydrocracking and hydrotreating. If extensive hydrocracking and hydrotreating are used, supplemental hydrogen is supplied by a hydrogen plant.

Steam reforming of light hydrocarbons (ranging from methane to naphtha) is currently the predominant process for hydrogen production in the United States. Steam reforming is a catalytic operation requiring four basic steps.

First, the desulfurized feed is catalytically "re-formed" into carbon monoxide and hydrogen by reaction with steam

(1500°F, 125 psig). Then the carbon monoxide formed is reacted with more steam in the catalytic shift conversion unit to produce CO<sub>2</sub> and an equivalent amount of H<sub>2</sub> (700°F, 120 psig). The third step is the removal of carbon dioxide by absorption (130°F) in an amine or potassium carbonate solution. The final step is the catalytic conversion of the remaining small quantities of CO and CO<sub>2</sub> into methane by reaction with hydrogen (800°F, 100 psig). The resultant hydrogen stream is moderately pure (98%+) with generally less than 10 ppm carbon dioxide.

#### 3.1.5.7 Blowdown System

The blowdown system provides for the safe disposal of hydrocarbons (vapor and liquid) discharged from pressure relief devices. Most units and equipment subject to planned or unplanned hydrocarbon discharges are manifolded into a collection unit, called the blowdown system.

A decreasing pressure system is used for safety and economic reasons. By using a series of flash drums and condensers arranged in decreasing pressure, the blowdown is separated into vapor and liquid cuts. The separated liquid is recycled. The gaseous cuts can either be smokelessly flared (steam injection) or recycled.

#### 3.1.5.8 Process Heaters

Process heaters (furnaces) are used extensively in refineries to supply the heat necessary to raise input materials to reaction or distillation temperature. They are used in many processes and are considered as a single process module to prevent unnecessary repetition.



Process heaters are usually designed to raise petroleum fluid temperatures to a maximum of about 950°F. The fuel burned may be refinery gas, natural gas, residual fuel oil or a combination, depending on the economics, operating conditions, and pollution requirements. The process heaters for CO waste heat boilers also use the carbon monoxide-rich regenerator flue gas as fuel. The fuel requirement for furnaces will range between 5 and 10 percent of the heating value of the raw crude entering the refinery.

### 3.2 Typical Energy Requirements

The petroleum refining industry is a highly energy-intensive industry. It has been estimated that a modern U.S. refinery will consume energy equivalent to 10 percent of the energy contained in the raw crude oil it processes. Roughly, this estimate can be attributed to process heaters (7.5%), steam consumption (1.5%), and electricity (1.0%) (DI-R-090).

Typical energy requirements of the basic refining processes are given in Table 3.2-1. Product handling operations are not included as the energy requirements are negligible.

### 3.3 Status and Geographic Distribution for Base Year

As of 1 January 1974, there were 142 companies which comprised the United States Petroleum Refining Industry. These companies operated 247 refineries in 39 states. Table 3.3-1 lists the 10 largest refiners and the production capacity of each along with the combined capacity of the other 169 refineries. A complete listing of the production capacities of all 247 refineries, by company, is found in Appendix C.

TABLE 3.2-1. TYPICAL ENERGY REQUIREMENTS OF BASIC PROCESSES

Process	Electricity (kwh/bbl)	Thermal Energy (Btu/bbl)	Steam (lb/bbl)
<b>Petroleum Separation Processes</b>			
1. Atmospheric Distillation	0.40	100,000	50
2. Vacuum Distillation	0.10-0.20	50,100	8
3. Light Ends Recovery	2.00	-	-
<b>Petroleum Conversion Processes</b>			
1. Catalytic Cracking			
Fluidized-bed	0.41	145,200	(74) <sup>1,2</sup>
Moving-bed (TCC)	0.10-1.50	100,000-300,000	100 (160)
2. Hydrocracking	7.64-14.00	145,000-252,500	10-16
3. Thermal Cracking			
Visbreaking	1.72	258,800	20 (100)
Coking	-	300,000-397,700	81 (182)
4. Catalytic Reforming	1.51	655,300	-
5. Alkylation	0.50-5.00	-	100-302 (lb/bbl product)
6. Isomerization	1.19	30,000-68,200	20-25
7. Polymerization	1.19	-	20
<b>Petroleum Treating Processes</b>			
1. Hydrotreating	0.05-0.25	2,500-5,000	0.15-0.25
2. Sweetening	0.04	-	-
3. Acid Gas Removal (unit/kg removed gas)	<0.01	-	0.28-0.56
4. Crude Desalting	0.01	22,000	-
5. Acid/Caustic Treatment	-	-	-
6. Solvent Treating	1.00	285,400	40
7. Desasphalting	0-3.18	80,200-139,000	30-140
8. Aromatics Extraction	0.80	190,000	2.5
9. Dewaxing/Deoiling	11.93-9.07	290,000-300,500	40/60
10. Asphalt Blowing	0.95	5,000-10,000	-
<b>Auxiliary Facilities</b>			
1. Sour Water Strippers	-	3,200	-
2. Wastewater Treatment	-	(500)	-
3. Cooling Towers	.0012 $\frac{\text{kwh}}{\text{gal}}$	-	-
4. Utilities Plant	-	1,200 $\frac{\text{Btu}}{\text{lb}}$	-
5. Sulfur Recovery (unit/MSCF)	<0.01	-	(11)
6. Hydrogen Plant	4.00	300,000	-
7. Blowdown Systems	-	-	-

<sup>1</sup>parentheses indicate production<sup>2</sup>production from CO boiler

Source: (DI-R-090, GA-182, HY-013)

TABLE 3.3-1. SUMMARY OF THE 10 LARGEST REFINERS

Company	Number of Refineries	Crude Capacity (BPD)
Exxon	5	1,244,175
Shell	8	1,102,068
Texaco	12	1,076,231
Amoco	10	1,058,343
Standard Oil of California	12	977,850
Mobil	8	926,175
Gulf	8	855,218
ARCO	6	784,862
Union Oil	4	483,956
Sun Oil	5	480,975
All Others	<u>169</u>	<u>5,152,800</u>
Total	247	14,142,656

Many of these companies are also involved in related industries, such as petrochemicals, which use refinery products as feedstocks. Petrochemical plants often border refineries to permit an easy exchange of products. These plants often generate by-product materials similar to refinery intermediate products which are then sold to the refinery.

Refineries are located in 39 states with the majority of refining capacity found near the coasts. There is considerable variation in the size of refineries which range from a production rate of 3125 barrels per day (BPD) to more than 400,000 BPD.

As shown in Appendix C, many refineries have crude capacities of less than 5,000 BPD. Economic operation of these small refineries is generally permitted only by production of specialty items, lube oils, or asphalts.

#### 3.4 Prospects for Growth Through 1985

The petroleum refining industry has been expanding at the rate of about 4 percent per year. The future rate of expansion is expected to remain the same. However, in census regions 1 and 3 a much faster growth rate is expected. The increased growth can be attributed to greater demand for petroleum products and the anticipated success of offshore exploration along the Atlantic Coast.

Conversely, census regions 6 and 8 display no growth potential. This lack of expansion is predominantly the result of geographic location. Petroleum refineries in these two regions rely on pipeline crude for the most part. Therefore,

the increased expense of pipeline crude coupled with declining internal domestic oil production indicates that refinery growth in these regions will be almost nonexistent.

#### 4.0 INDUSTRY GROWTH PROJECTION METHODOLOGY

The objective of this study is to determine the energy penalty due to environmental controls over a time frame from 1974 to 1985. To accomplish this, it is necessary to predict the growth pattern of the industry. The total capacity in 1980 and 1985 is important, of course, but the geographical distribution and the size of each expansion is also necessary to fully define the industry.

##### 4.1 Sector and Subsector Definitions

A close examination of the refining industry was made to determine if the sector and subsector approach would be beneficial. It was found that petroleum refining was sufficiently homogeneous to be treated as a whole. If the study had been of the entire petroleum industry, it would definitely have required a disaggregate study of production, refining, transportation, and marketing. Refining alone, however, does not necessitate such an approach.

##### 4.2 Sources of Data

The baseline production data presented in Form 2, Appendix B, were developed from two sources. The data for 1974 were taken from the "Mineral Industry Surveys - Crude Petroleum, Petroleum Products, and Natural Gas Liquids: 1974" issued by the Bureau of Mines (US-575). The data for 1980 and 1985 were based on several economic forecasts described in more detail below.

Since the 1973-1974 oil embargo, the prediction of energy availability and usage patterns has been the subject of many studies. Two extensive studies were chosen since they condensed the previous work and allowed a more efficient overview

of available data. These were the 1976 National Energy Outlook by the FEA (FE-153) and A Western Regional Energy Development Study by the Stanford Research Institute (ST-381).

These sources provided a good means for estimating the total production of the industry, but further data were required to determine the probable geographic and size distribution of the projected growth. Industry periodicals such as the Oil and Gas Journal and Hydrocarbon Processing were searched for announcements of planned expansion (CA-339, HY-038). These data were augmented by an FEA report (PE-177) and a private communication from the EPA (WA-290). The results of this survey of planned expansions are shown in Table 4.2-1. While these construction plans were not used verbatim to project industry growth, they were useful as a guide in allocating the new capacity indicated by previous studies into the proper geographic and size categories.

#### 4.3        Industry Growth Models

While this study is concerned only with petroleum refining, the growth models used must consider expansion in all phases of the petroleum industry. Table 4.3 shows the various cases developed in the two major studies cited earlier (FE-153, ST-381). The primary variable separating these cases is the market price of crude oil. But conservation efforts, development of Alaskan and Outer Continental Shelf reserves, development of alternate energy sources, and changes in government policies are also considered. All cases are based on a healthy economy, compatible with a steady increase in the Gross National Product of about 3.3% per year.

These varied cases were judged on two main criteria to determine their applicability to this study:

TABLE 4.2-1. ANNOUNCED REFINING EXPANSION PLANS, 1976

Company/Location	Type	Stage	PAD	AQCR	Capacity (BPD)
Hunt Oil (Tuscaloosa) <sup>1</sup>	E	C	III	4	15,000
Louisiana Land & Exploration (Mobile) <sup>1</sup>	N	C	III	5	30,000
Marion Corp. (Theodore) <sup>2,3</sup>	E	E	III	5	2,000
Standard Oil Co. (Pascagoula) <sup>1</sup>		C	III	5	54,000
Tesoro-Alaskan Petr. Corp. <sup>2,3,5</sup>	N		V	9	18,000
Delta Refining (Memphis) <sup>2</sup>	E		II	18	4,700
J&W Rfy. Co. (Tucker) <sup>2</sup>	E	C	III	22	6,000
California Oil & Purification (Ventura) <sup>1,3,4</sup>	N	E	V	24	15,000
Douglas Oil Co. Calif. (Paramount) <sup>1</sup>	E	C	V	24	15,000
Lundray-Thagard Oil Co. (South Gate) <sup>2,3,6</sup>	E		V	24	3,300
Standard Oil Co. Calif. (El Segundo) <sup>1,2,3,4</sup>	E	U	V	24	175,000
Standard Oil Co. Calif. (Richmond) <sup>1,2,3,4</sup>	E	U	V	30	175,000
Standard Oil Calif. (Perth Amboy) <sup>1,2,3,4</sup>	E		I	43	80,000
Gulf Oil Co. (Philadelphia) <sup>2</sup>	E		I	45	30,000
Rock Island Rfy. Corp. (Indianapolis) <sup>1,2</sup>	E	U	II	80	7,000
Gladieux Rfy. Inc. (Ft. Wayne) <sup>2,1</sup>	E	C	II	81	2,500
Somerset Rfg. Inc. (Somerset) <sup>2,3,7</sup>	E		II	105	1,600
American-Petrofina (Port Arthur) <sup>2,3,4,8</sup>	E	E	III	106	30,000
ECOL (Garyville) <sup>2,3</sup>	N		III	106	200,000
Exxon (Baton Rouge) <sup>2,3,9</sup>	E		III	106	11,000
Good Hope (Good Hope) <sup>4</sup>	E	U	III	106	50,000
Gulf Oil (Port Arthur) <sup>1,2,4</sup>	E	UorE	III	106	23,000
Kerr-McGee (Wynnewood) <sup>1</sup>	N	C	II	188	16,000
Champlin Petr. Co. (Corpus Christi) <sup>1,2,3,4,10</sup>	E	U	III	214	60,000
Sader Refining Co. (Corpus Christi) <sup>2</sup>	N		III	214	12,000
Sigmar (Three Rivers) <sup>3</sup>	N		III	214	10,000
Three Rivers Rfy. (Three Rivers) <sup>2</sup>	E	U	III	214	5,000



TABLE 4.2-1 ANNOUNCED REFINING EXPANSION PLANS, 1976 (Continued)

Company/Location	Type	Stage	PAD	AQCR	Capacity (BPD)
Atlantic Richfield (Houston) <sup>1,2,3,4,11</sup>	E	U	III	216	93,000
Penzoil-United Inc. (Falling Rock) <sup>1,2</sup>	E	U	I	234	40,000
<u>1977</u>					
Mallard Expl. Inc. (Atmor) <sup>1</sup>	N	E	II	5	7,000
Energy Co. of Alaska (Fairbanks) <sup>1,2,3,4,12</sup>	N	E	V	9	25,000
Midland Corp. (Cushing) <sup>3,4</sup>	E	UorE	II	17	16,000
California Oil Purification (Ventura) <sup>3,4</sup>	E	E	V	24	15,000
Standard Oil California (Perth Amboy) <sup>1,2</sup>	E	E	V	43	30,000
Shell Oil Co. (Woodriver) <sup>1</sup>	E	E	II	70	30,000
Tenneco (Chalmette) <sup>1,2,3,4,13</sup>	E	E	III	106	30,000
Steuart Petr. Co. (Piney Point) <sup>1,21</sup>	N	P	I	116	100,000
Gulf Oil (Luling) <sup>3,4</sup>	N	P	III	212	30,000
Exxon (Baytown) <sup>1,2,3,4,14</sup>	E	U	III	216	250,000
<u>1978</u>					
Odessa Rfg. Inc. (Mobile) <sup>1,4,15</sup>	N	E	III	5	120,000
Crown Central Petr. Corp. (Baltimore) <sup>1,16</sup>	N	E	I	115	200,000
Dow Chem. Co. (Freeport) <sup>2,3,4,17</sup>	N,E	P	III	214	200,000
Hudson Oil Rfg. (Bayport) <sup>1,18</sup>	N	P	III	216	200,000
Hampton Roads Energy Co. (Portsmouth) <sup>2,3,4,19</sup>	N	P	I	223	184,000
Virco (St Croix) <sup>4</sup>	N	P		247	200,000
<u>1979</u>					
Pittston Co. (Eastport) <sup>3,4</sup>	N		I	109	250,000
Cascade Energy Resources (Rainier) <sup>4</sup>	N		V	193	200,000

TABLE 4.2-1. UNCERTAIN, UNDEFINED OR EARLY STAGES OF PLANNING

Company/Location	Type	Stage	PAD	AQCR	Capacity (BPD)
Wallace & Wallace (Tuskegee) <sup>3,4</sup>	N		III	2	150,000
Odessa Rfg. Inc. (Mobile) <sup>1,4</sup>	N		I	5	120,000
Tesoro-Alaskan Petr. Corp. (Kenai) <sup>4,2</sup>	E	P	V	8	17,000
PIMA (Phoenix) <sup>3</sup>	N		V	15	3,000
Atlas Processing (Shreveport) <sup>4</sup>	E	UorE	III	22	40,000
J&W Refining (Tucker) <sup>3</sup>	E		III	22	150,000
Penzoil (Shreveport) <sup>2</sup>	E		III	22	40,000
Atlantic Richfield (Wilmington) <sup>4</sup>	N	P	V	24	20,000
Newhall Rfg. (Newhall) <sup>1,3,4,20</sup>	E		V	24	4,000
Powerine Oil (Santa Fe Springs) <sup>4,1</sup>	E	E	V	24	25,000
Macario Indep. Rfy. (Carlsbad) <sup>4,1</sup>	N	P	V	29	100,000
Pacific Resources (San Diego) <sup>3</sup>	N		V	29	100,000
Urich (Martinez) <sup>3,4</sup>	N		V	30	30,000
In-O-Ven (New London) <sup>3</sup>	N		I	41	400,000
Pepco (Saybrook) <sup>3</sup>	N		I	42	400,000
Shell (Gloucester) <sup>3</sup>	N		I	45	150,000
Conoco-Dillingham Oil (Barbers Point) <sup>4,1</sup>	N	E	V	60	50,000
HIRI (Eua Beach) <sup>4,1</sup>	E	P	V	60	20,000
HIRI (Ohau) <sup>3</sup>	E		V	60	65,000
Texaco (Lockport) <sup>3,4,1</sup>	E		II	67	25,000
Clark (Hartford) <sup>3</sup>	E		II	70	4,000
JOC Oil (Romeville) <sup>4</sup>	N	P	III	160	200,000
Le Gardeur Int. (Braithwaite) <sup>3,4</sup>	N		III	106	300,000
Texaco (Convent) <sup>3,4</sup>	N		III	106	200,000
Gibbs Oil Co. (Sanford) <sup>3</sup>	N		I	110	250,000
Crown Central Petr. (Baltimore) <sup>1,3,4</sup>	N		I	115	200,000
Saber-Tex (Dracut) <sup>3</sup>	N		I	119	100,000
Granite State Refs. (Rochester) <sup>3</sup>	N		I	121	400,000
Olympic Oil Refs. (New Market) <sup>3</sup>	N		I	121	400,000
United Refining (West Branch) <sup>3</sup>	E		II	122	5,000
Lakeside Rfg. Co. (Kalamazoo) <sup>1</sup>	E	U	II	125	?

TABLE 4.2-1 UNCERTAIN, UNDEFINED OR EARLY STAGES OF PLANNING (Continued)

Company/Location	Type	Stage	PAD	AQCR	Capacity (BPD)
New England Petr. (Oswego) <sup>1,4</sup>	N		I	158	200,000
Cirillo Bro. (Albany) <sup>3,4</sup>	N		I	161	20,000
Vickers Petr. Corp. (Ardmore)	E	U	II	188	60,000
Cascade Energy Resources (Portland) <sup>1</sup>	N		V	193	30,000
Charter Oil (St. Helens) <sup>4</sup>	N	P	V	193	30-50,000
Columbia Indep. Rfy. (Portland) <sup>3</sup>		P	V	193	50,000
Pacific Resources (Portland) <sup>3</sup>	N		V	193	50,000
Saber Rfy. (Corpus Christi) <sup>2</sup>			III	214	12,000
Amoco (Texas City) <sup>4</sup>	E	U	III	216	?
Charter Intl. (Houston) <sup>4</sup>	E	U	III	216	?
Hudson Oil (Bayport) <sup>3</sup>	N		III	216	100,000
Phillips Co. (Sweeny) <sup>4</sup>	E	P	III	216	65,000
Texas City Rfy. (Texas City) <sup>4</sup>	E	U	III	216	?
Hampton Roads Energy Co. (Portsmouth) <sup>2,2</sup>	N		I	223	184,000

<sup>1</sup> HPI: February 1976

<sup>2</sup> OGJ: April 26, 1976

<sup>3</sup> PE-177; Trends in Refining Capacity and Utilization; December 1975

<sup>4</sup> EPA Listing

<sup>5</sup> OGJ = 18,000\*; FEA = 17,000 (A star will indicate the value used in this table)

<sup>6</sup> OGJ = 6,800; FEA = 3,300\*

<sup>7</sup> OGJ = 5,000; FEA = 1,600\*

<sup>8</sup> OGJ = 26,000; FEA = 34,000; EPA = 30,000\*

<sup>9</sup> OGJ = 11,000\*; FEA = 10,000

<sup>10</sup> OGJ = 52,000; EPA, FEA = 60,000\*

<sup>11</sup> HPI, OGJ = 95,000; FEA, EPA = 93,000\*

<sup>12</sup> HPI, OGJ = 25,000\*; FEA, EPA = 15,000

<sup>13</sup> OGJ = 35,000; HPI, FEA, EPA = 30,000\*

<sup>14</sup> OGJ, HPI = Complete in 1976; FEA, EPA = Complete in 1977\*

TABLE 4.2-1 ANNOUNCED REFINING EXPANSION PLANS (Continued)

- <sup>15</sup> Uncertain on EPA listing
- <sup>16</sup> EPA, FEA listed as uncertain
- <sup>17</sup> OGJ, HPI = Complete in 1977; FEA, EPA = Complete in 1978\*
- <sup>18</sup> FEA listed as uncertain
- <sup>19</sup> OCJ = 184,000; FEA, EPA = 175,000\*; Uncertain due to opposition on environmental grounds
- <sup>20</sup> FEA = 4,000\*; EPA = 10,000
- <sup>21</sup> FEA listed as planned but not constructed due to opposition on environmental grounds
- <sup>22</sup> FEA listed for 1978; EPA opposed on environmental grounds (Washington Post 4-20-76)

Type: E - Expansion  
N - New

Stage: P - Planning  
E - Engineering  
U - Under construction  
C - Completed

TABLE 4.3-1 SUMMARY OF CRUDE OIL DEMAND PROJECTIONS

Source	Date	Case	Petroleum Demand (MMBPD)						Bases
			1980			1985**			
			Domestic *	Imports	Total	Domestic *	Imports	Total	
1976 - National Energy Outlook - Federal Energy Administration (FE-153)	Feb. 1976	\$13/BBL business as usual	12.8	4.4	17.2	13.9	5.9	19.8	Assumes - a world oil price of \$13/BBL, oil and gas deregulation occurs over the next few years, OCS leasing proceeds according to Department of Interior announced leasing schedule, tertiary recovery methods are moderately applied, present provisions of federal tax codes which impact crude oil economics remain unchanged.
		\$13/BBL Conservation				14.0	3.8	17.8	Based on the same assumptions as the \$13/BBL BAU case with the additional assumption that a determined effort will be made to reduce total energy demand by the use of energy saving devices.
		\$13/BBL accelerated supply and conservation				16.0	1.4	17.4	Besides the basic assumptions of the \$13/BBL case, this projection assumes an accelerated OCS leasing program, greater production from shale oil and tertiary recovery, more optimistic resource estimates, and the conservation effort of the previous case.
		\$13/BBL imported oil - domestic oil regulation at \$7.50/BBL				9.9	11.3	21.2	
		\$13/BBL imported oil - domestic oil regulation at \$9/BBL				11.5	9.4	20.9	
		\$13/BBL imported oil - domestic oil supply pessimistic 9/BBL domestic oil				9.6	12.6	22.2	Assumes - domestic oil regulated at \$9/BBL, less favorable geological and technical developments than the BAU case.
		\$8/BBL business as usual	11.9	7.6	19.5	11.4	13.5	24.9	Assumes - a world oil price of \$8/BBL and moderate development as in \$13/BBL BAU.
	\$16/BBL business as usual	13.1	3.4	16.5	15.0	3.3	18.3	Assumes - a world oil price of \$16/BBL and moderate development as in \$13/BBL BAU.	

\*Natural gas liquids are included in the domestic totals of these projections.

\*\*Synthetic liquids are not included in these totals.

TABLE 4.3-1 SUMMARY OF CRUDE OIL DEMAND PROJECTIONS (Continued)

Source	Date	Case	Petroleum Demand (MMBPD)						Bases
			1980			1985**			
			Domestic* Production	Imports	Total	Domestic* Production	Imports	Total	
A Western Regional Energy Development Study - Stanford Research Institute (SI-381)	Dec. 1975	Historical Growth				11.8	8.2	20.0	Assumes - energy and petroleum consumption will grow at historical rate. Based on Ford Foundation Scenario (F0-027).
		Technical Fix				11.6	3.4	15.0	Assumes - a determined national effort to reduce demand for energy by application of energy saving technologies. Based on Ford Foundation technical fix scenario (F0-027).
		Nominal Case	10.0	~4.9	14.9	11.7	4.6	16.3	Nominal case used by SRI adds of the difference between historical growth and technical fix scenario to the baseline of the technical fix scenario.
Analysis for National Science Foundation - Check Systems	Feb. 1975				19.8			21.4	
Petrochemicals and Energy in Perspective - CEP Shell Chemical (RE-149)	March 1975				18.5			19.9	
Petroleum Storage for National Security - (NPC (NA-261))	Aug. 1975	High Range of Import Projections		10.2			12.5		
		Low Range of Import Projections							
		Calculated Medium		7.8			8.4		

\*Natural gas liquids are included in the domestic totals of these projections.

\*\*Synthetic liquids are not included in these totals.

- 1) each scenario should represent a realistically attainable situation, and
- 2) the scenarios chosen for study should bound the range of possible developments.

Application of these criteria yielded three cases:

Maximum case - \$13/bbl Supply Pessimistic - FEA  
Minimum case - \$13/bbl Accelerated Supply - FEA  
"Most Likely" case - \$13/bbl Business As Usual - FEA

The "\$13/bbl Business As Usual" case was chosen as the most significant for this study. It essentially represents the average of all cases, and its basic assumptions seem to be the most realistic.

#### 4.4 Major Assumptions

Once given the overall demand for petroleum products, an assumption needs to be made about the level of refining activity. It is possible that domestic refining capacity will expand to accommodate the increased petroleum demand, or this demand will be met by importing refined products. The stated government energy policies would seem to favor the former, calling for an energy supply that is independent of foreign powers. On the other hand, the expansion of domestic refineries may pose problems in attaining the National Ambient Air Quality Standards.

There are clearly two opposing forces here, and it is difficult to predict which will prevail or if some compromise will be found. For the purposes of this study, it was assumed that domestic refineries will grow to meet the increased petroleum

demand. This will provide a study basis that encompasses all possible refining formats (expansion of existing refineries, grassroots refineries, etc.). It should also be much easier to remove the effect of new growth from the calculations, if necessary, than to add the growth effect later if it was required.

#### 4.5 Caveats and Limitations

Predicting the future is always an endeavor filled with uncertainty. Under the best conditions, where the given phenomenon has performed in a regular manner historically and there seems to be no impetus to change, the uncertainty is still considerable.

While the petroleum industry has had a fairly uniform historical growth, the last decade has shown divergence. Many recognized forces are at work which could greatly alter the future growth of refining. Some of the major ones are:

- Government policy changes including tax incentives, price controls, offshore leasing, forced allocation of crude and/or products, safety regulations, environmental regulations, and punitive efforts to increase the competitive nature of the industry (vertical or horizontal divestiture).
- Development of new technology in the fields of exploration, alternate energy forms, and enhanced recovery of known reserves.
- Changes in public opinion, especially as they affect conservation measures and the siting of refineries and production facilities.



- Changes in the world-wide energy distribution as affected by OPEC and the emerging nations.

These non-quantifiable factors naturally add a great deal of uncertainty to this projection.

Since completion of the Draft Final Report, governmental policies have changed in the energy area. Legislation such as the National Energy Policy and the requirements for increasing automobile efficiency have placed pressure against rising refinery crude oil demand. One result of this has been a slightly lower growth in motor gasoline demand than predicted by the model chosen. This should have a minimal effect on the overall accuracy of the calculated energy penalties, however, since the penalties are expressed on a per barrel of crude basis. The only effect could come in slightly over estimating penalties, because of stricter controls on new capacity, which are then averaged with the penalties for existing capacity. If this predicted capacity increase does not materialize, the industry average penalty would be lower than predicted. Conversely, the predicted penalties would be too low if actual capacity expansion exceeds the predicted expansion. Since the projected growth of new capacity is only about 5.7% per year, these effects should be minimal.

## 5.0 BASELINE ENERGY CONSUMPTION METHODOLOGY

In order to determine the relative impact of the increased energy consumption due to environmental controls, it is necessary to determine the baseline energy consumption with no controls. The baseline production data will then allow the calculation of an energy consumption per unit of production which can be extrapolated into the future.

### 5.1 Calculation of Process Requirements

The base year was chosen as 1974 because full year data were available, the level of existing environmental controls was relatively low, and it was recent enough to accurately represent the modern refining industry. The base year energy consumption data were taken from the Bureau of Mines Annual Petroleum Statement (US-595). These data are presented in Form 1, Appendix B.

There were some environmental controls in effect in 1974, however, and the actual energy consumption figures must be adjusted for this to determine a true "no control" baseline energy requirement. These data are presented in Table 5.1. It is interesting to note that if all pollution control equipment is attributed to environmental regulation requirements, there is a net decrease in the overall refinery energy requirement. This effect is caused by the waste energy recovery of the Carbon Monoxide (CO) Boilers in use on many cracking units. In fact, many of the CO Boilers in operation in 1974 were not required by any environmental regulation. Therefore, it is evident that the CO Boilers were being justified on the basis of energy conservation, and that the pollution abatement aspect was only a side effect. The bottom section of Table 5.1-1 shows the energy penalty for environmental controls neglecting CO Boilers. This yields a

TABLE 5.1-1. BASELINE ENERGY CONSUMPTION

	All units are in $10^3$ Btu/Bbl									
	Census Region No.									
	1	2	3	4	5	6	7	8	9	Wt. National Average
Actual 1974 Energy Consumption	0	690	750	550	640	576	753	608	654	678
Energy Penalty for Existing Controls	0	(8)	(5)	(6)	(4)	(12)	0	(1)	(1)	(3)
Adjusted 1974 Energy Consumption with "no controls"	0	698	755	556	644	588	753	609	655	681
Energy Penalty for Existing Controls (neglecting CO Boiler)	0	8	5	8	5	5	10	4	11	9
Adjusted 1974 Energy Consumption with "no controls" except CO Boilers	0	682	745	542	635	571	743	604	643	669

more reasonable number, a weighted national average penalty of 9000 Btu per barrel of crude processed. Since the actual consumption in 1974 averaged 678,000 Btu/bbl, the true baseline energy consumption was 669,000 Btu/bbl.

The penalty for existing controls devoted exclusively to pollution abatement was, therefore, only about 1.3% of the baseline consumption. This difference between actual 1974 consumption and the true baseline consumption need not be considered in the projected baseline consumptions for 1980 and 1985, since it is of negligible magnitude in comparison to the uncertainties of forecasting the industry production levels (see Sections 4.3 and 4.4).

## 5.2 Allocation Among Fuel Types

The BOM data were discretely expressed in the actual fuel types used in 1974. Each fuel type was projected to maintain its share of the energy requirements for 1980 and 1985, except for natural gas. The current natural gas shortages, resulting in curtailment of industrial consumption in order to meet residential needs, make it unlikely that natural gas can maintain its share of the refinery fuel market. It was assumed for this study, that natural gas would supply only half of its 1974 share in 1980, and would not be used at all in 1985. Fuel oils were chosen as the most likely replacement.

The balance of purchased versus self-generated electricity was also considered. Economic factors are currently favorable for self-generation in refineries. Since a refinery requires large amounts of steam for the process units, it is possible to generate this steam at a higher pressure than needed and reduce pressure through a turbine driving a generator. The efficiency of this scheme is considerably higher than that

attained by an electric utility company, and with rising fuel costs this provides a strong incentive. The modification of existing equipment is a very capital intensive operation, however, and this may deter any large scale conversion. It would be most attractive in the larger plants and in new construction. For the purposes of this study, it was assumed that self-generation of electricity would only maintain its current level.

There is some uncertainty about what constitutes a purchased fuel or a self-generated fuel in a refinery, since its principal products are fuels. Fuel oils were listed on Form 1 as purchased fuels, even though they were very likely produced in the refinery where they were burned. The rationale for this is that the fuel oils consumed in the refinery would be sold if they were not burned. Therefore, by relinquishing the potential income from the fuel oils consumed internally, the refinery is purchasing the fuel from itself. Refinery fuel gas and catalytic coke were listed as self-generated fuels since there was no outside market to which they could be diverted.

### 5.3 Regionalization

The 1974 data from the BOM were presented by state. It was a simple matter to group these states into their appropriate census districts. Data for 1980 and 1985 were extrapolated from 1974 data using the growth models described in Section 4.3.

### 5.4 Projected Changes Through 1985

The refining industry is dynamic, always in a process of internal change, but there are no great changes forecast in refinery fuel implementation through 1985. The major effect will be the application of more sophisticated pollution control equipment and its inherent energy drain. Counteracting this effect

will be industry conservation efforts. In addition, refined products specifications have historically become progressively stricter in order to meet the needs of more sophisticated end use machinery. This trend should continue.

While research into alternate energy forms is being actively and successfully pursued, this will have little bearing on the refining industry fuel slate. While coal, solar power, nuclear power, etc. show great promise, these energy sources are not expected to overcome the logical convenience of burning petroleum based fuels in a refinery.

The application of alternate energy technology outside refining may eventually slow the growth in demand for fossil fuels. It can even be anticipated that petroleum derivatives will someday be far too valuable as chemical feedstocks to be used as fuels at all. But these developments are beyond the time frame of this study.

## 5.5 Caveats and Limitations

The figures for 1974 actual and baseline energy consumption are firm. Consumptions for 1980 and 1985 are subject to variation. The major factors introducing uncertainty are:

- Dependence on fluctuating foreign crude supplies,
- Lack of a firm, comprehensive national energy policy,
- Effectiveness of public energy conservation measures,

- Development and application of alternate energy forms, and
- Possible technology improvements in refining processes, pollution control equipment, and/or end use machinery (mainly automobiles).

## 6.0

### ENERGY PENALTY METHODOLOGY

This section describes the methods used to estimate the energy penalties which result from refinery compliance with environmental regulations. This penalty is defined as the incremental demand for energy above a baseline demand that would occur in the absence of any federally enforceable environmental regulations. The method that was used to estimate the energy penalties first analyzes the environmental regulations which impact the petroleum refining industry. Then the various environmental control strategies available to the refining industry are reviewed. Finally, the actual energy penalty calculations are summarized, and the section concludes with a discussion of how the refining industry was regionalized for the study and how the energy penalties are distributed according to fuel types.

## 6.1

### Identification of Major Environmental Regulations and Standards

The environmental regulations and standards covered in this study are limited to those which are enforceable by the federal government. Those federally enforceable regulations impacting the refining industry were reviewed and the regulations which result in potentially significant energy penalties were selected. This section identifies those regulations and standards which were chosen on that basis. The pollutants covered include particulates, SO<sub>2</sub>, NO<sub>x</sub>, CO, HC, lead, and wastewater. The following discussion presents a review by pollutant of the regulations which were selected for this study.



### 6.1.1 Particulate Regulations

In defining the four regulatory scenarios for the control of particulates, three types of regulations were considered: State Implementation Plans (SIP), New Source Performance Standards (NSPS), and the Reasonable Available Control Technology (RACT). While RACT is actually a hypothetical control regulation, it is an important indication of the impact of implementing the most severe particulate control regulations.

For the control of particulate emissions, State Implementation Plans concentrate basically on combustion units, process units, and catalytic cracking units (see Appendix A, Table A-1). Although regulations vary widely among the states, some are more common than others. For instance, most states set the maximum allowable particulate emissions from combustion units at about  $0.6 \text{ lb/hr}/10^6 \text{ Btu}$ . Similarly, many states limit particulate emissions according to process weights. Therefore, for a process weight (P) less than or equal to 30 ton/hr, the allowable emission rate (lb/hr) is equal to  $4.10 (P)^{0.67}$ . For larger process weights, the emission rate becomes  $[55.0(P)^{0.11}] - 40$ . Most states consider catalytic cracking units as process units.

Presently NSPS applies only to steam generators and catalytic crackers. For either coal, oil, or gas-fired boilers the maximum allowable particulate emission rate is  $0.10 \text{ lb}/10^6 \text{ Btu}$ . For catalytic crackers particulate emissions cannot exceed  $1.0 \text{ lb}/1000 \text{ lb}$  of coke burnoff in the regenerator.

In applying RACT values the objective was maximum particulate emission control. The result was to apply three types of particulate control measures in a staged arrangement which achieved 99.95% theoretical efficiency.

### 6.1.2 Sulfur Dioxide Regulations

In defining the six regulatory scenarios for the control of sulfur dioxide emissions, five types of regulations were considered: State Implementation Plans, New Source Performance Standards, the most Reasonable Available Control Technology, and desulfurization of all petroleum products to either 0.7% or 0.3%. Presently the only federally enforceable regulations are SIP and NSPS.

For the control of SO<sub>2</sub> emissions, State Implementation Plans concentrate basically on combustion units, process units, and sulfur recovery units (see Appendix A, Table A-2). In all three instances, there is no common regulation. For combustion units several states rely on various means of control. For example, some states regulate the sulfur content of the fuel according to weight percent, while other states regulate the effluent by ppm SO<sub>2</sub>. Still others limit the emission rate as an allowable lb SO<sub>2</sub>/10<sup>6</sup> Btu heat input. For process units and sulfur recovery units the regulations are more consistent. Most states regulate the effluent by ppm SO<sub>2</sub>, with allowable values ranging from 500 to 2000.

Presently NSPS applies only to steam generators greater than 250 million Btu/hr and fuel gas combustion. For coal-fired boilers the allowable emission rate is 1.2 lb SO<sub>2</sub>/10<sup>6</sup> Btu and for oil fired boilers the allowable emission rate is 0.80 lb/10<sup>6</sup> Btu. NSPS also require that any fuel gas be less than 0.1 grain H<sub>2</sub>S/dscf (KE-181). Proposed rules would also limit the concentration of sulfur dioxide in the gases discharged to the atmosphere from a sulfur recovery unit to 0.025 percent by volume at zero percent oxygen and on a dry basis.

In applying RACT regulations the objective was maximum SO<sub>2</sub> emission control. For the most part, this meant hydrodesulfurization of fuel oils marketed for use in industrial and utility process heaters and boilers. RACT also required tail gas cleanup on all sulfur recovery units. To control SO<sub>2</sub> from the catalytic cracker, two options are available: hydrodesulfurization of feed or flue gas scrubbing.

The final two sets of regulations did not limit emissions as such, but limited the sulfur content of petroleum products to 0.7 weight percent and 0.3 weight percent, respectively. The major aim of these regulations was to decrease the SO<sub>2</sub> emissions associated with burning fuels (distillate, gas oil, and resid) by decreasing the sulfur available in the fuels. These regulations would not affect other products such as gasoline and jet fuel, which already meet these specifications.

#### 6.1.3 Nitrogen Oxides Regulation

Current federally enforceable regulations for nitrogen oxide emissions from petroleum refining are the State Implementation Plans (SIP) and New Source Performance Standards (NSPS). A list of the SIP NO<sub>x</sub> regulations by state is given in Appendix A, Table A-3.

The only source of NO<sub>x</sub> emissions in refineries subject to regulation are the fuel combustion units. Most SIP regulations limit only the amount of NO<sub>x</sub> emitted from units with greater than 250 million Btu per hour heat input. Common SIP emission limits are 0.2 pounds NO<sub>x</sub> per million Btu of heat input for gas-fired units and 0.3 pounds NO<sub>x</sub> per million Btu for oil fired units. The New Source Performance Standard for NO<sub>x</sub> emissions from fuel combustion is also 0.2 lbs/million Btu for

gas and 0.3 lbs/million Btu for oil. The Control Strategies section of this report describes the common control techniques used by industry to reduce NO<sub>x</sub> emissions from fuel combustion.

Besides the SIP and NSPS regulations, a regulation was used in the study which assumed the required application of reasonable available control technology (RACT). This regulation was intended to represent a "strictest case" of regulation for NO<sub>x</sub> emission control. For purposes of energy penalty calculations it was assumed to apply to all fuel combustion sources of NO<sub>x</sub> with greater than 250 million Btu per hour heat input. The limits of NO<sub>x</sub> emission chosen were 0.2 lbs NO<sub>x</sub>/million Btu for gas firing and 0.3 lbs NO<sub>x</sub>/million Btu for oil firing.

#### 6.1.4 Carbon Monoxide Regulations

Twenty states have written specific carbon monoxide emission limitations in their SIP's. Fourteen of these apply to existing and new units, while the other six are strictly for new sources. All new sources will also be under the regulation of the Federal New Source Performance Standards (NSPS) which allow a maximum of 0.05 volume % CO emissions from a catalytic cracker.

The only significant source of carbon monoxide emissions in petroleum refineries is the catalytic cracking catalyst regenerator. Before federally enforceable CO standards existed well over half of the total catalytic cracking capacity was equipped with CO boilers (SH-306). This is because in most cases there is a net energy saving to the refiner once CO boilers are installed. As energy costs escalate in the future the economic advantage of CO boilers will become even more pronounced.

This reasoning led to the assumption that CO boilers were not installed for environmental reasons, but rather for economic reasons. Therefore, no energy penalties, or credits in this case, were calculated due to the installation and operation of CO boilers. While this assumption may not be true for every case of a CO boiler installation, it is believed that this assumption describes the real world situation with the least error within the scope of this study.

#### 6.1.5 Hydrocarbon Regulations

Current federally enforceable regulations for hydrocarbon emissions from petroleum refining are the State Implementation Plans (SIP) and New Source Performance Standards (NSPS). A list of the SIP hydrocarbon regulations by state is given in Appendix A, Table A-5.

Those sources of hydrocarbon emissions in refineries which are regulated by SIP's and whose control leads to significant primary and/or secondary energy penalties include gasoline tank car and tank truck loading racks, oil-water separators, vapor blowdown, and storage tanks. The typical SIP requirement for loading racks is control by vapor recovery. For oil-water separators floating covers are usually required. Vapor blowdown is controlled by flaring. Storage tanks containing volatile hydrocarbon liquids are usually required by SIP regulations to be controlled by floating roofs, vapor recovery system, or pressure tanks depending on vapor pressure. The New Source Performance Standards for hydrocarbon emissions from refineries refer only to hydrocarbon storage. The NSPS requires floating roof tanks, pressure tanks, or vapor recovery systems depending on vapor pressure.

Another regulation was used in the study besides the SIP and NSPS regulations. This regulation was developed to determine the energy penalty for the "strictest case" of hydrocarbon emission control. The regulation applied to tank car/truck loading racks, oil-water separators, vapor blowdown, and storage tanks. The requirements of this regulation are vapor recovery systems for loading racks, floating covers for oil-water separators, smokeless flares for vapor blowdown control, and floating roofs and pressure tanks for storage tank control.

#### 6.1.6      Lead Regulations

The removal of lead anti-knock additives from gasoline has been the subject of heated debate since 1970. Although there is some evidence that airborne lead may be a health hazard, the impetus for unleaded gasoline was primarily to satisfy the requirements of the catalytic muffler. Since the catalytic converter was to become standard equipment on the 1975 model year cars, it was mandated that all major refiners make unleaded gasoline available by July 1, 1974. Total pool lead reduction had already been in effect since 1971 when low lead gasoline was introduced, but market acceptance of this grade was very low. The 1975 and later cars were equipped with a special filter neck that would not accept a leaded gasoline nozzle, so the use of unleaded gasoline has risen proportionally to the influx of new cars. This market demand for unleaded gasoline was considered to be the most lenient regulatory scenario for this study.

In an effort to reduce airborne lead levels more rapidly than demand for unleaded gasoline would accomplish, total pool lead phasedown schedules have been promulgated. Several versions of the phasedown timetable have been modified at the request of

refiners, who claimed that they were unable to comply with proposed schedules. The current phasedown criteria allows waivers of the intermediate lead levels for refiners who can show that they are taking good faith steps to meet the ultimate level of less than 0.5 gram of lead additive per gallon of the total gasoline pool. This would require a reduction in the lead level in regular and premium grades as well as the production of unleaded gasoline. This lead phasedown was chosen as the second regulatory scenario.

The strictest regulatory scenario would obviously be the complete exclusion of lead from gasoline. Calculations for this case were made only for 1985, since it would not be technologically feasible in the earlier study years. This scenario will probably occur even if not required by law. The replacement of the auto population with new models requiring unleaded gasoline will make it economically unattractive to maintain segregated marketing facilities for the small portion of cars that can use leaded gasoline.

#### 6.1.7 Water Regulations

Current federally enforceable regulations for water effluents from petroleum refining are the State Water Laws, the Effluent Limitations Guidelines, and New Source Performance Standards. A list of the State Water Laws as they apply to the refining industry is given in Appendix A, Table A-7. Also listed in Table A-7 are the Effluent Limitations Guidelines and New Source Performance Standards.

The State Water Laws limit the discharge of any pollutant to state waters from any point source by requiring that a certain level of control be applied to the source. For the refining industry the level of control is either primary or

secondary treatment. The Effluent Limitations Guidelines and New Source Performance Standards specifically describe the level of control which must be applied to refinery effluents. These guidelines call for all existing refinery sources to have secondary-level waste treatment facilities by 1977 and tertiary treatment and wastewater flow reductions by 1983. For new sources the guidelines require secondary treatment and wastewater flow reductions.

## 6.2 Control Strategies

This section of the report presents the control strategies which were developed for the given regulatory scenarios. The control technology represents current state-of-the-art application as well as projected control technology needed to meet 1980 and 1985 requirements. Particulate control strategies are discussed first, followed by SO<sub>2</sub>, NO<sub>x</sub>, HC, lead, and water. Table 6.2-1 presents a summary of the control strategies used for each of the pollutants.

### 6.2.1 Particulates

The two major sources of particulate emissions from petroleum refinery operations are process heaters and boilers and fluidized-bed catalytic cracking units. For process heaters and boilers there is no technically practical means to clean the flue gas from so many diverse sources. As a result, the best means of control is to limit the types of fuel which can be burned. Based on emission factor data, the particulate emissions from residual oil and distillate oil combustion are 0.154 lb/10<sup>6</sup> Btu and 0.108 lb/10<sup>6</sup> Btu, respectively (EN-071). Many State Implementation Plans and the New Source Performance Standards have chosen to regulate fuels by allowing particulate emissions not to exceed 0.10 lb/10<sup>6</sup> Btu.



TABLE 6.2-1. SUMMARY OF CONTROL STRATEGIES

Regulatory Scenario	Regulatory Scenario	CONTROL STRATEGY MIX #				
		1	2	3	4	5
1	Particulates SIP (Existing Sources)	Multiple Internal Cyclones (MIC)	MIC plus Electrostatic Precipitator (ESP)	MIC plus a Wet Scrubber		
2	Particulates SIP (New Sources)	MIC	MIC plus ESP	MIC plus a Wet Scrubber		
3	Particulates NSPS	MIC	MIC plus ESP	MIC plus a Wet Scrubber		
4	Particulates RACT	MIC plus ESP	MIC plus a Wet Scrubber	MIC, ESP, and a Wet Scrubber		

TABLE 6.2-1. (Continued)

Regulatory Scenario	Regulatory Scenario	CONTROL STRATEGY MIX #				
		1	2	3	4	5
5	SO <sub>2</sub> SIP (Existing Source)	Selective Fuel Blending; Claus Unit	Blending plus some Gas Oil HDS; Claus Unit	Blending plus HDS of FCC Feed; Claus Unit with Tail Gas Treating	No. 3 plus Gas Oil HDS	Blending Gas Oil HDS, FCC Flue Gas Scrubbing; Claus Unit with Tail Gas Treating
6	SO <sub>2</sub> SIP (New Sources)	Selective Fuel Blending	Blending plus some Gas Oil HDS; Claus Unit	Blending plus HDS of FCC Feed; Claus Unit with Tail Gas Treating	No. 3 plus Gas Oil HDS	Blending Gas Oil HDS, FCC Flue Gas Scrubbing; Claus Unit with Tail Gas Treating
7	SO <sub>2</sub> NSPS	Selective Fuel Blending	Blending plus some Gas Oil HDS; Claus Unit	Blending plus HDS of FCC Feed; Claus Unit with Tail Gas Treating	No. 3 plus Gas Oil HDS	Blending Gas Oil HDS, FCC Flue Gas Scrubbing; Claus Unit with Tail Gas Treating
8	SO <sub>2</sub> RACT	Selective Fuel Blending	Blending plus some Gas Oil HDS; Claus Unit	Blending plus HDS of FCC Feed; Claus Unit with Tail Gas Treating	No. 3 plus Gas Oil HDS	Blending Gas Oil HDS, FCC Flue Gas Scrubbing; Claus Unit with Tail Gas Treating
9	SO <sub>2</sub> 0.7 wt. % S Fuel	Selective Fuel Blending	Blending plus some Gas Oil HDS; Claus Unit	Blending plus HDS of FCC Feed; Claus Unit with Tail Gas Treating	No. 3 plus Gas Oil HDS	Blending Gas Oil HDS, FCC Flue Gas Scrubbing; Claus Unit with Tail Gas Treating
10	SO <sub>2</sub> 0.3 wt. % S Fuel	Selective Fuel Blending	Blending plus some Gas Oil HDS; Claus Unit	Blending plus HDS of FCC Feed; Claus Unit with Tail Gas Treating	No. 3 plus Gas Oil HDS	Blending Gas Oil HDS, FCC Flue Gas Scrubbing; Claus Unit with Tail Gas Treating

TABLE 6.2-1. (Continued)

Regulatory Scenario	Regulatory Scenario	CONTROL STRATEGY MIX #				
		1	2	3	4	5
11	NO <sub>x</sub> SIP (Existing Units)	Two State Combustion	Flue Gas Recirculation			
12	NO <sub>x</sub> SIP (New Units)	Two Stage Combustion	Flue Gas Recirculation			
13	NO <sub>x</sub> NSPS	Two Stage Combustion	Flue Gas Recirculation			
14	NO <sub>x</sub> RACT	Two Stage Combustion	Flue Gas Recirculation			

TABLE 6.2-1. (Continued)

Regulatory Scenario	Regulatory Scenario	CONTROL STRATEGY MIX #				
		1	2	3	4	5
15	Hydrocarbon SIP (Existing Sources)	Blowdown vented to flares; Pressure tanks	No. 1, plus floating roof tanks and vapor recovery systems	No. 2, plus floating cover or API separators	No. 3, plus Afterburner or Boiler-Incinerator on the FCCU	
16	Hydrocarbon SIP (New Sources)	Blowdown vented to flares; Pressure tanks	No. 1, plus floating roof tanks and vapor recovery systems	No. 2, plus floating cover or API separators	No. 3, plus Afterburner or Boiler-Incinerator on the FCCU	
17	Hydrocarbon NSPS	Floating roof tanks, Blowdown vented to flares; Pressure tanks	No. 1, plus vapor recovery systems	No. 2, plus floating cover or API separators	No. 3, plus Afterburner or Boiler-Incinerator on the FCCU	
18	Hydrocarbon RACT	Floating roof tanks, vapor recovery, pressure tanks, blowdown to flares, floating cover on API separator, and Afterburner or Boiler-Incinerator on the FCCU				

TABLE 6.2-1. (Continued)

Regulatory Scenario	Regulatory Scenario	CONTROL STRATEGY MIX #				
		1	2	3	4	5
19	Produce Unleaded Gasoline to Meet Market Demand	Increase Processing Severity to Improve Octanes	Some severity increase plus the use of a non-lead additive			
20	Lead Phasedown to <0.5 gm/gal of the Total Pool by 10-1-79	Increase Processing Severity to Improve Octanes	Some severity increase plus the use of a non-lead additive			
21	Zero Lead in Gasoline	Increase Processing Severity to Improve Octanes	Some severity increase plus the use of a non-lead additive			

TABLE 6.2-1. (Continued)

Regulatory Scenario	Regulatory Scenario	CONTROL STRATEGY MIX #				
		1	2	3	4	5
22	State Waste-water Treatment Requirements	Sour Water Stripping, API Separators, Dissolved Air Floatation, Equalization Basin, Clarification, Trickling Filters	No. 1 with Un-aerated Lagoons Replacing Trickling Filters	No. 2 with Aeration Towers Replacing Un-aerated Lagoons	No. 3 with Aerated Lagoons Replacing Aeration Towers	No. 4 with Activated Sludge Replacing Aerated Lagoons
23	BPCTCA-Federal Effluent Limitations	Sour Water Stripping, API Separators, Dissolved Air Floatation, Equalization Basin, Clarification, Trickling Filter, Filtration	No. 1 with Un-aerated Lagoons Replacing Trickling Filters	No. 2 with Aeration Towers Replacing Un-aerated Lagoons	No. 3 with Aerated Lagoons Replacing Aeration Towers	No. 4 with Activated Sludge Replacing Aerated Lagoons
24	BADT-Federal Effluent Limitations	Sour Water Stripping, API Separators, Dissolved Air Floatation, Equalization Basin, Clarification, Trickling Filter, Filtration plus Reduction in Flow	No. 1 with Un-aerated Lagoons Replacing Trickling Filters plus Reduction in Flow	No. 2 with Aeration Towers Replacing Un-aerated Lagoons plus Reduction in Flow	No. 3 with Aerated Lagoons Replacing Aeration Towers plus Reduction in Flow	No. 4 with Activated Sludge Replacing Aerated Lagoons plus Reduction in Flow
25	BATEA-Federal Effluent Limitations	Sour Water Stripping, API Separators, Dissolved Air Floatation, Equalization Basin, Clarification, Trickling Filter, Filtration, Carbon Adsorption, Reduction in Flow	No. 1 with Un-aerated Lagoons Replacing Trickling Filters plus Reduction in Flow	No. 2 with Aeration Towers Replacing Un-aerated Lagoons plus Reduction in Flow	No. 3 with Aerated Lagoons Replacing Aeration Towers plus Reduction in Flow	No. 4 with Activated Sludge Replacing Aerated Lagoons plus Reduction in Flow

In the fluidized-bed catalytic cracker the particulate emissions result from coke burnoff in the catalyst regenerator. Three possible control strategy mixes have been proposed. One means of control would be the use of multiple internal cyclones (MIC). Multiple cyclones have only slightly higher efficiencies (90% for particles  $>5\mu$ ) than one large cyclone, but usually require less space (LU-013). A second method of particulate control is the combination of multiple internal cyclones and an electrostatic precipitator (ESP). The addition of the electrostatic precipitator increases the overall collection efficiency to about 99.5% (JO-086). The third control strategy mix consisted of multiple internal cyclones followed by a wet scrubber. The wet scrubber considered here was a jet-ejector venturi scrubber designed by Exxon, which claims a particulate collection efficiency of 90% (EX-001). By combining multiple internal cyclones and a wet scrubber, the overall efficiency is about 99.0%.

#### 6.2.2 Sulfur Dioxide

The three major sources of sulfur dioxide emissions from petroleum refining operations are process heaters and boilers, fluidized-bed catalytic cracking units, and sulfur recovery units. The control of sulfur dioxide emissions requires complicated arrangement of various process units. Five different control strategy mixes were proposed ranging from the most common arrangement presently used by the refinery industry to an arrangement utilizing the most reasonable available technology.

In calculating the effectiveness of each process unit the following sulfur removal efficiencies were assumed:

Naphtha HDS	}	
Distillate HDS		
Gas Oil HDS		
Resid HDS		90%
Gas Treating Plant (GA-182)		99.99%
Claus Sulfur Recovery Unit (GA-182)	95%	} 99.8%
Scot Tail Gas Treatment (HY-014)	96%	
FCC Flue Gas Scrubber (EX-001)		97%

All five control strategy mixes were assumed to use naphtha hydrodesulfurization, distillate hydrodesulfurization, and gas treating plants as a matter of accepted industry practice. Therefore, in calculating energy penalties and secondary impact indicators, only the necessary incremental capacities were considered.

The most reasonable means of controlling SO<sub>2</sub> emissions from process heaters and boilers is to control the sulfur content of the fuels. In 1974 such control represents no significant difficulty, but in 1980 and 1985 the amount of sour crude being processed will have increased tremendously and the use of gas oil hydrodesulfurization and resid hydrodesulfurization will be important factors in meeting low sulfur fuel demands.

The control of SO<sub>2</sub> emissions from fluidized-bed catalytic cracking units can be accomplished in one of two ways. The most common method has been to desulfurize the FCC feed. The near-absence of sulfur in the feed results in a much lower SO<sub>2</sub> concentration in the flue gas. Recently Exxon has proposed flue gas scrubbing as a viable alternative to FCC feed desulfurization. Exxon has installed a commercial size unit at their Baytown and Baton Rouge refineries and preliminary indications of SO<sub>2</sub> removal have been very favorable.



Sulfur recovery units are the third potential source of SO<sub>2</sub> emissions from petroleum refining operations. Sulfur recovery units are necessary to convert high H<sub>2</sub>S concentrations in acid gas into the more disposable by-product elemental sulfur. The most common practice is to use a modified Claus plant, usually equipped with a reheat scheme and up to four catalytic converters. The EPA suggests for Claus sulfur plants, an SO<sub>2</sub> emission limitation of 0.01 lbs of SO<sub>2</sub>/lb of sulfur processed. This is about one tenth of the typical emission found in most Claus plant stacks and will result in the addition of some type of tail gas cleaning unit (GO-214). Although several tail gas cleaning processes are available, for the purposes of this study the SCOT process was chosen because of its similarity to other refinery processes, the economical materials of construction, and the low SO<sub>2</sub> emissions (less than 250 ppm SO<sub>2</sub> after incineration).

Each of the five control strategy mixes is an arrangement of the emission control operations discussed. In addition the degree of these operations may also differ within a control strategy mix. For example, fuels hydrodesulfurization may imply hydrodesulfurization of either gas oil, residual oil, or both, depending upon the severity of the regulation being considered.

#### 6.2.3 Nitrogen Oxides Control Strategies

The only source of nitrogen oxides from petroleum refineries that is subject now or is expected to be subject in the future to federally enforceable regulations is fuel combustion. Currently, these regulations apply to steam boilers with greater than 250 million Btu per hour heat input. Two control strategies were developed which satisfy the regulatory

scenarios used in this study. The first control strategy is two-stage combustion. The second is flue gas recirculation. Both control strategies have primary and secondary impacts associated with their use.

Two stage combustion has the effect of fuel rich burner operation on boiler  $\text{NO}_x$  formation. Two-stage combustion works on the principles of off-stoichiometric combustion except that the fuel-rich burner operation is achieved by diverting a portion of the total required air through separate ports located above the burner pattern. This has the effect of lowering  $\text{NO}_x$  formation by lowering peak flame temperature.

The flue gas recirculation control technique reduces  $\text{NO}_x$  formation by reducing both the peak flame temperature and partial pressure of available oxygen at the burner inlet. This is accomplished by recirculating a portion of the boiler flue gas back to the primary combustion zone.

#### 6.2.4 Hydrocarbon Control Strategies

Four sources of hydrocarbon emissions from refineries were chosen for this study on the basis of the primary and/or secondary impact of their control. These sources are tank truck/car loading racks, oil-water separators, vapor blowdown, and storage tanks. Alternative control strategies were developed for the regulations which apply to these sources. The control strategies vary according to regulatory scenario and stringency. Included in Table 6.2-1 (Regulatory Scenarios 15-18) are the control strategies that were used for this study. A description of each control technique for the hydrocarbon sources listed follows.

The control of tank truck/car loading racks is usually only required for petroleum products with vapor pressures greater than 1.5 psia. Those State Implementation Plans which do require control of emissions from loading operations usually specify vapor collection and recovery. The vapor collection systems are manifolded into a vapor recovery unit either for conversion of the hydrocarbon vapors into liquid product by condensation or compression or for disposal of the vapors through such processes as combustion or absorption. Most systems are capable of achieving 90 percent reduction of hydrocarbon emissions. For energy penalty calculations, condensation of the collected vapors was assumed.

Where control of oil-water separators is required, vapor loss control devices on the units are generally specified. Vapor loss control devices can be a floating cover or a vapor recovery system. Since floating covers are much simpler and more economical they are preferred over vapor recovery systems. The floating cover on the separator acts much the same as does the floating roof used to control storage tank emissions. By eliminating the vapor space above the liquid surface, the volatile components of the wastewater are not allowed to evaporate.

Vapor blowdown occurs in a refinery due to unit start-ups, shutdowns, process venting, process upsets, power failures, or natural catastrophies. The hydrocarbon blowdown is collected in a system which vents the gases to flares for combustion. Liquids in the blowdown stream are separated by knock-out drums. For the purpose of calculating energy penalties, flares were assumed to be required for all refineries even though their use was not stated specifically in each regulation. Smokeless operation was also assumed which requires the addition of steam to the flare tip during combustion. Flaring results in a 99+ percent control of vapor blowdown emissions. Flaring also results in both primary and secondary impacts.

The control of hydrocarbon emissions from storage tanks depends upon two factors. First, the vapor pressure of the liquid stored generally determines what type of control is required. For liquids with true vapor pressures greater than 11.0 psia, pressure tanks or vapor recovery systems are required by most regulations. Pressure tanks are commonly used in refineries for storing highly volatile products, and vapor recovery applications to storage control are limited due to high costs. For liquids with true vapor pressures from 1.5 psia to 11.0 psia, floating roof tanks or vapor recovery systems are required by most regulations. Floating roof tanks are used almost exclusively to control emissions because of their economic advantages over vapor recovery systems.

The second factor determining storage tank control is the capacity of the tank. The State Implementation Plans generally limit regulation to tanks with capacities greater than 40,000 gallons. This includes virtually all refinery tankage. The New Source Performance Standards apply only to tanks with capacities greater than 40,000 gallons, also.

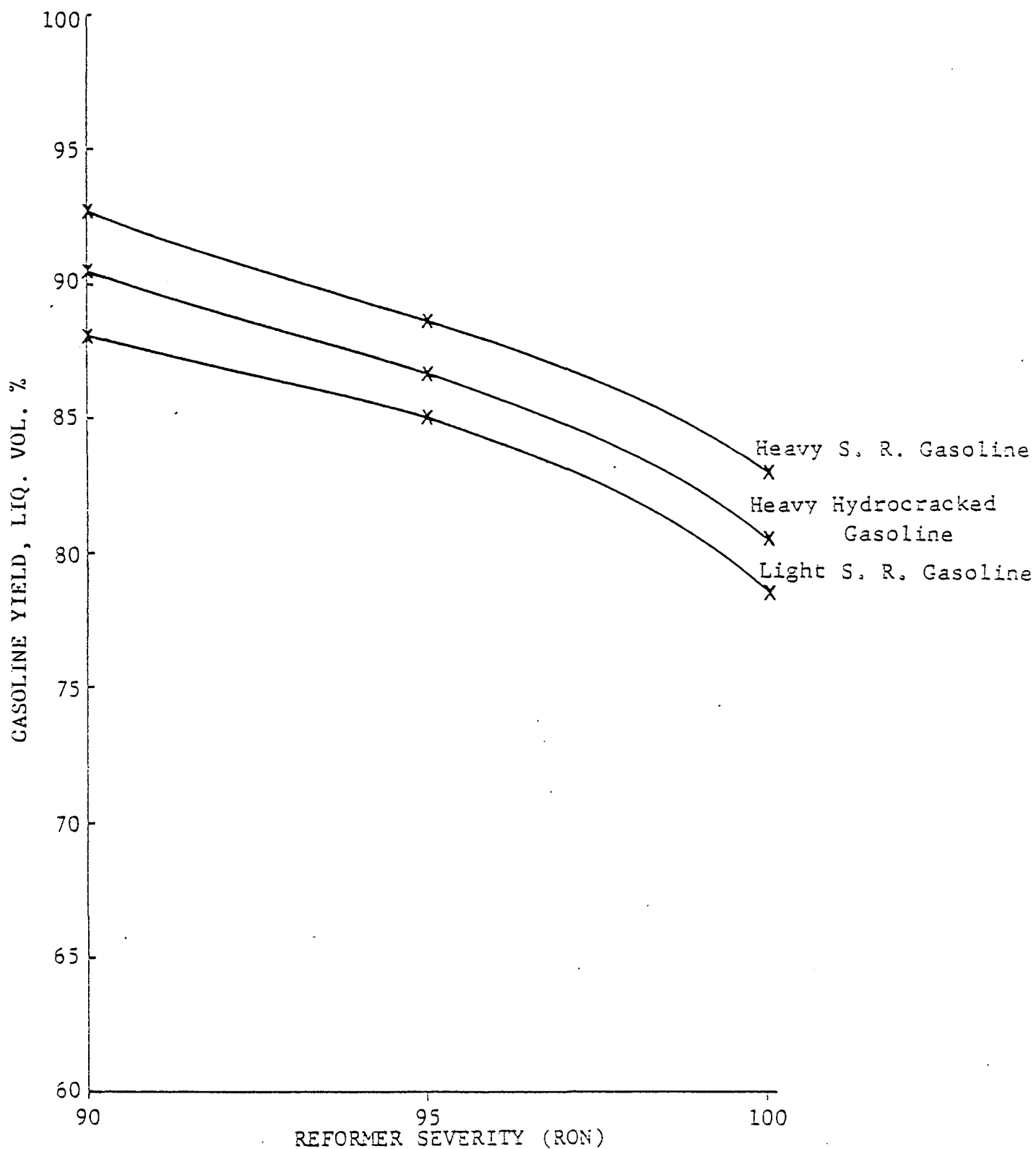
#### 6.2.5 Lead Control Strategies

The purpose of lead additives in gasoline is to increase the octane number, which is merely a numerical measure of the tendency of an engine to "knock" on a given fuel. There are a number of alternatives which can compensate for the removal of lead. One would be to modify the internal combustion engine so that it could operate satisfactorily on lower octane fuels. This was done, at least in part, when auto makers cut the compression ratio of their engines to accommodate fuel with an octane similar to "regular" gasoline instead of "premium." This was a necessary, but not a sufficient adjustment. Thus, the refiner is left with two alternatives, increasing process severity or using a non-lead based additive to increase the octane number of his product gasoline.

There are already many processes at work in the refinery whose purpose is octane improvement. The most important of these is the Catalytic Reforming Unit (CRU). Just as the name implies, this unit reforms low octane normal paraffin components into isoparaffins, naphthenes, and aromatics. Typical operation of such a unit would upgrade the gasoline to about a 90 Research Octane Number (RON). This is usually termed a severity of 90. The production of substantial amounts of unleaded gasoline requires that reformer severity be raised to an eventual limit of about 100. This requires more energy in the form of fuel to the heaters, but the worst effect is the decrease in yield. Figure 6.2-1 graphically demonstrates a typical yield/severity relationship. It should be noted that the yield drops ever more sharply with increasing severity. This is due to the increase in the unwanted side reaction, hydrocracking, which breaks the gasoline components into butanes, propanes, and fuel gas. This loss of gasoline yield means that more naphtha must be run to yield the same volume of higher octane product. This necessitates additional construction of reformer capacity, and therefore an increase in energy consumption.

Another important process in octane boosting is the Fluid Catalytical Cracking Unit (FCCU). Although the primary function of the FCCU is to increase the gasoline supply by cracking heavier gas oils, the way in which this is accomplished can have considerable effect on pool octane. Cracking at higher reactor temperatures can provide a several octane number increase in cracked gasoline. This will be accompanied by the production of more of the reactive propylene and butylene which feed Alkylation and Polymerization units, also producers of high octane gasoline. This high temperature cracking is accompanied by increased energy consumption, both in fuel to the feed preheater and in incremental coke yield burned in the regenerator.

Figure 6.2-1. Reformer Yield/Severity Relationship



The Alkylation process builds a gasoline molecule from two molecules of light hydrocarbon. One of the feed molecules must be isobutane, and the other must be an olefin such as propylene, butylene, or pentylene. The result is a very high octane gasoline stock with good volatility characteristics. More alkylation capacity will be needed to compensate for lead removal, and this is a very energy intensive process. The Polymerization process builds gasoline from three olefin molecules. This gasoline is somewhat lower in quality, and this process will play a negligible part in replacing lead.

The Isomerization process changes straight chain paraffins into branched chains, and by doing so raises the octane number. This will be used primarily for five and/or six carbon gasoline molecules. Isomerization is important in that it produces high octane gasoline with a relatively low boiling point. This high volatility octane is very important to engine performance, especially as the higher boiling aromatics are concentrated by high severity reforming.

The combination of all the above processes is required in varying proportions to satisfy the octane needs of various regions and refinery configurations. This general control strategy is called increasing process severity.

The other unique control strategy would be the replacement of lead with a non-lead based anti-knock additive. There are several possibilities, but probably the most promising is methylcyclopentadienyl manganese tricarbonyl, or MMT as it is commonly called. Preliminary data from General Motors indicate that above a certain level MMT may pose a problem of clogging the catalytic converter. However, because of the low concentration of MMT in gasoline proposed in this report, it is believed

that MMT is a viable anti-knock additive. Furthermore, there is no evidence that manganese poses a health hazard (UN-072). MMT is currently in use in "trimming" blends of unleaded gasoline. This is the process of correcting a blend whose octane falls below the specification. It is much easier to add a few pounds of MMT, than to add hundreds of barrels of high octane blending stock. This is an efficient and desirable process, since it allows the refiner to let his target octane on the blend approach the octane specification more closely, thus reducing costly over-refining.

While the routine use of MMT on a large scale has been delayed by its cost, it becomes more economically feasible as the octane requirement increases. It is presently felt that an optimum concentration of MMT would be 0.125 grams per gallon (BA-459). This would provide a two to three octane number improvement in most unleaded blends. While this obviously does not replace the eight to ten octane number loss with lead removal, it is of great benefit in reducing the degree of increased processing severity necessary. Thus, the use of a non-lead additive, specifically MMT, in conjunction with some increase in process severity is the refiners second control strategy.

#### 6.2.6 Water Control Strategies

The discharge of wastewater from refineries was included in this study on the basis of the primary and secondary impact of its control. The control strategies vary according to regulatory scenario and stringency. Included in Table 6.2-1 (Regulatory Scenarios 22-25) are the control strategies that were used for this study.



The control strategies developed vary from primary level treatment to tertiary level treatment. The State Water Laws enforceable in 1974 called for either primary treatment of refinery wastes or secondary treatment. The Federal Effluent Guidelines require secondary treatment for refineries by 1977 and tertiary level treatment by 1983.

### 6.3        Engineering Calculation Methodology

This section describes how the primary energy penalties were calculated. Basically, for each pollutant this involved first determining which environmental controls had primary energy impacts. (Secondary energy impacts are discussed in Section 8.0). Then, the number and size or capacity of the control units were estimated. For 1974, this involved gathering information on the extent of application of each control method. For 1980 and 1985 this involved estimating control usage based on projected refinery growth and projected regulatory scenarios. After determining the number and size of the controls, the energy penalties were estimated by using energy consumption data for each type of control. Appendix B, Form 5 contains the results of the energy penalty calculations.

#### 6.3.1      Particulates

In calculating energy penalties for the control of particulate emissions, the only process unit to consider is the fluidized-bed catalytic cracker. Typical data on an FCC indicate that approximately 0.242 lb of particulates/bbl feed are emitted for uncontrolled conditions (EN-071). Using this figure as a basis, the energy penalty calculation was a four step process.

- 1) Check the specific control regulation (see Appendix A) for the AQCR under consideration and determine the allowable emission rate.
- 2) From data on refinery capacity and FCC throughput for that region, calculate the uncontrolled emission rate using 0.242 as the base figure.
- 3) Using the rates calculated in the previous two steps, determine percent collection efficiency necessary to meet the specific control regulation.
- 4) The necessary control efficiency will determine which control strategy mix will satisfy the regulation. For each satisfactory control strategy mix calculate the required capacity and energy consumption. Typical power requirements are given in Table 6.3-1.

#### 6.3.2 Sulfur Dioxide

In calculating energy penalties for the control of sulfur dioxide emissions, there were three basic process units to consider: process heaters and boilers, the fluidized-bed catalytic cracker, and the sulfur recovery plant. The sulfur dioxide emissions from each unit are indirectly related to the others. For example, the increasing demand for low sulfur fuels

TABLE 6.3-1. TYPICAL ENERGY REQUIREMENTS FOR  
POLLUTION CONTROL EQUIPMENT

	Electricity (Kwh/unit)	Thermal Energy (Btu/unit)	Steam (lb/unit)
Multiple Cyclones	-	-	-
Scrubbers (10 <sup>3</sup> scf)	0.202	-	-
Electrostatic Precipitators (10 <sup>3</sup> scf)			
High Voltage	0.003 - 0.010	-	-
Low Voltage	0.0002-0.0007	-	-
Hydrodesulfurization (bbl)			
Distillates	2.55	123,000	50.5
Gas Oil/FCC Feed	2.55	123,000	50.5
Residual Oil	4.4	64,000	2.7
Amine Gas [Sweetening](scf)	3,000		0.25
Claus Unit (1b Feed)	0.0025	-	(0.817)*
SCOT Unit (1b Feed)	0.0053	68.34	0.10

\* parenthesis indicate production

necessary to meet SO<sub>2</sub> emission limitations for industrial and utility process heaters and boilers has resulted in increasing hydrodesulfurization of gas oils. The sulfur rich off-gas from an HDS unit ultimately passes through an amine treatment unit and arrives at a sulfur recovery plant, thus increasing SO<sub>2</sub> emissions at this point.

Therefore, each of the five proposed control strategy mixes was drawn as a process flow sheet, detailing the movement of sulfur (lb sulfur/Mbbl. crude charged) through the various process units from crude oil input to sulfur recovery. Such a flow sheet arrangement provided an accurate means of calculating the process rates and associated SO<sub>2</sub> emissions for important refinery units. Each flow sheet was based on the assumption that gas oil is the primary FCC feed and 90% of the gas oil from atmospheric and vacuum distillation is used for this purpose. In addition, each flow sheet was adjusted to reflect the product character of each region according to data on FCC capacity (bbl FCC feed/bbl crude charged).

A standard procedure was followed in calculating energy penalties:

- 1) Check the applicable control regulation (see Appendix A) for the AQCR under consideration and determine the allowable emission rates for process heaters and boilers, FCC units, and sulfur recovery units.
- 2) From data on refinery capacity and FCC throughput for that region, use a control strategy mix flow sheet to calculate the emission rates for process heaters and boilers, FCC units, and sulfur recovery units.

- 3) Using the emission rates calculated in the previous two steps, determine which of the five control strategy mixes meets the applicable regulations. Failure to meet the emission limitation in only one of the three main areas of concern, eliminates a control strategy mix from consideration in that AQCR.
- 4) For each suitable control strategy mix calculate the required capacity and energy consumption. Typical power requirements are given in Table 6.3-1.

It should be noted here that hydrodesulfurization of fuel oils results in lowering the heating content of the fuel. The loss in heating value varies with process severity, but is in the neighborhood of 2-3 percent of the fuel's total heating value. However, this loss in heating value is not a primary energy penalty as the penalty is defined in this report. For this reason, this loss is not included in calculating the hydrodesulfurization energy penalty.

#### 6.3.3 NO<sub>x</sub>-Engineering Calculation Methodology

Those NO<sub>x</sub> control units used in 1974, and projected to be used in 1980 and 1985, which result in primary energy penalties are exhaust gas recirculation and two-stage combustion. Federally enforceable regulations for NO<sub>x</sub> emissions from fuel combustion apply only to units with greater than 250 million Btu/hr heat input. A description of how the energy penalties associated with NO<sub>x</sub> control were calculated follows.

Refineries with greater than 100 MBPD capacity may be expected to have steam generators with greater than 250 million Btu/hr capacity. For each Census Region for 1974, 1980 and 1985, the capacity of refineries in the region greater than 100 MBPD was totaled. Using a factor developed to estimate the energy penalty for exhaust gas recirculation (20 Btu/bbl of crude capacity) and two-stage combustion (80 Btu/bbl of crude capacity) overall regional energy penalties were calculated (TH-116). Penalties were calculated only for those units which burned oil since gas fired units generally meet emission limits without control. See Appendix B, Forms 5, Regulatory scenarios 11, 12, 13, and 14 for tabulated results. The penalties are reported as Purchased Oil.

#### 6.3.4 Hydrocarbon-Engineering Calculation Methodology

The hydrocarbon control techniques used in 1974 and projected to be used in 1980 and 1985 which result in primary energy penalties are the vapor recovery units used for loading rack control and vapor blowdown flares. A description follows of how the energy penalties associated with each of these control techniques was calculated.

For vapor recovery systems used to control loading rack emissions an average system energy requirement per thousand gallons of motor gasoline loaded was first calculated. This number, 2 Kw-hrs per  $10^3$  gallons, was calculated from results published in a previous Radian report (BU-217). For the regions requiring control this number was applied to estimates of the gasoline output transported by tank car or tank truck and the resulting energy penalty was determined. Appendix B, Form 5, Regulatory Scenarios 15 through 18 present the results. The penalties are reported as Purchased Electricity.

For the flaring of vapor blowdown an energy requirement per pound of hydrocarbon flared was first determined. From results published in the literature an average energy requirement for steam of 560 Btu per pound of hydrocarbon flared was estimated (DA-069). Also, an average number was obtained for the quantity of hydrocarbon flared at refineries, 0.19 percent of refinery feed (KL-081). By applying these numbers to regional refinery throughputs, the energy penalties due to vapor blowdown flaring were calculated.

#### 6.3.5 Lead-Engineering Calculation Methodology

The calculation of energy penalties attributable to lead phasedown required two steps:

- determine the process changes required to raise the pool octane enough to offset the removal of lead and
- determine the incremental energy consumption of these process changes.

The first step was accomplished by the interpretation and regionalization of the results of The Impact of Lead Additive Regulations on the Petroleum Refining Industry as prepared for the EPA by Arthur D. Little, Inc. (LI-151). Incremental energy consumption was determined by the use of utilities factors taken from the literature and by heat balances around the units concerned.

The A.D. Little report was one of a three volume study which examined the impacts of lead, sulfur in gasoline, and SO<sub>2</sub> regulations on petroleum refining. In the course of these

studies, a linear programming (LP) computer model of the industry was made based on six regional cluster models. These models were carefully chosen and calibrated to simulate the actual industry. The complicated gasoline blending values and lead susceptibilities were submitted both to the refiners and the lead additive manufacturers for review and comment. This resulted in a sophisticated program which could adjust the internal processing to make various product specifications. This report consumed much time and effort, and it would not have been feasible to duplicate this work in the time frame of this energy penalty study. A. D. Little did not emphasize the energy consumption aspect, but was concerned with the overall impacts of capital expenditures, operating expenses, and energy penalties. The results of their LP model were the basis of our more detailed examination of the energy penalties. Examples of the LP model output as adapted to Region 2 are shown in Tables 6.3-2 and 6.3-3. These present the unit processing scheme and gasoline blending results, respectively. ADL's cases were defined as:

- Case A - No restrictions on the use of lead additives,
- Case B - Manufacture of unleaded gasoline to meet the market demand, and
- Case C - EPA's proposed lead phasedown.

The second phase of the calculation required the application of unit energy consumption factors to the increased processing detailed above. Four basic refinery units were involved:



TABLE 6.3-2. A. D. L.'s L. P. MODEL RESULTS - PROCESSING AND VARIABLE OUTPUTS  
East Coast Cluster - Region 2

	Scenario A			Scenario B			Scenario C		
	1977	1980	1985	1977	1980	1985	1977	1980	1985
Variable output									
Gasoline Mbb1/CD	110.972	111.524	110.785	110.424	109.817	106.915	109.109	108.723	106.915
LPG Mbb1/CD	4.634	3.954	3.981	4.402	4.910	6.119	5.579	5.561	6.119
Sulfur tons/CD	112	111	109	103	104	114	104	106	114
SO <sub>x</sub> emissions tons/CD	52	52	54	50	51	59	51	54	59
Processing Mbb1/CD									
Reforming									
Total	47.1	47.0	47.0	47.9	45.8	46.5	47.8	45.8	46.5
For gasoline	43.6	43.5	43.5	44.4	42.3	43.0	44.3	42.3	43.0
Severity for gasoline	90.0	90.0	90.1	92.3	95.6	100.0	97.0	98.0	100.0
Catalytic cracking									
Untreated feed	55.2	58.2	56.8	53.4	58.5	62.2	55.6	60.5	62.2
Hydrotreated feed	--	--	--	--	--	--	--	--	--
Total	55.2	58.2	56.8	53.4	58.5	62.2	55.6	60.5	62.2
Conversion Vol %	80.4	78.3	79.1	84.4	81.9	83.6	85.0	84.1	83.6
Hydrocracking									
High severity	8.2	3.9	4.1	9.0	6.7	1.4	5.4	4.2	1.4
Medium severity	5.2	9.5	9.4	--	2.3	8.0	3.8	5.1	8.0
Total	13.4	13.4	13.5	9.0	9.0	9.4	9.2	9.3	9.4
Isomerization of light naphtha									
Once through	--	--	--	--	0.6	0.1	0.2	3.2	0.1
Recycle	--	--	--	--	--	7.6	--	0.2	7.6
Total	--	--	--	--	0.6	7.7	0.2	3.4	7.7
Alkylation (product basis)	9.5	9.5	9.5	10.5	11.1	12.9	11.4	12.6	12.9
Hydrogen manufacture (MMSCF/CD)	32.9	29.9	30.6	25.7	24.6	20.7	24.2	22.7	20.7
Desulfurization									
Light naphtha (isom. feed)	--	--	--	--	0.6	7.7	0.2	3.4	7.7
Medium naphtha (ref. feed)	36.1	37.9	37.7	37.6	36.3	36.5	38.1	35.8	36.5
Cat cracker cycle oil	3.4	5.3	4.5	0.7	2.4	4.1	0.1	2.3	4.1
Straight run distillate	18.0	12.4	10.6	20.2	15.3	12.9	19.7	13.7	12.9
Total	57.5	55.6	52.8	58.5	54.6	61.2	58.1	55.2	61.2

TABLE 6.3-3. A. D. L.'s L. P. MODEL RESULTS - GASOLINE BLENDING

Cluster: East Coast - Region 2	Year						
	1977			1980			1985
	A	B	C	A	B	C	A
<b>Scenarios</b>							
<b>Premium Pool</b>							
Research octane	92.7	92.7	94.9	92.7	92.4	96.6	92.8
Motor octane clear	83.5	83.3	86.3	83.6	82.8	87.8	83.8
Volume Mbb1/CD	29.96	16.56	16.37	36.80	4.39	4.35	44.31
Lead CC/USG	3.00	3.00	1.53	3.00	3.00	0.97	3.00
Sulfur ppm	686	568	304	448	714	2	722
<b>Composition LV%</b>							
Butanes	8.0	9.1	10.9	8.8	6.3	8.0	7.7
90 RON reformat	0.4	7.8	--	21.4	--	--	3.0
100 RON reformat	--	--	17.6	--	--	46.3	--
Cat cracker gasoline (untreated feed)	59.4	54.3	28.8	40.9	64.5	--	61.2
Alkylate	23.0	24.3	41.7	23.5	22.3	41.5	20.2
Light hydrocrackate	9.2	--	--	5.4	--	--	7.9
Isomerized light naphtha	--	--	1.0	--	--	4.2	--
Straight run	--	4.5	--	--	6.9	--	--
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0
<b>Regular Pool</b>							
Research octane clear	85.5	85.8	87.7	85.4	83.9	88.4	84.5
Motor octane clear	77.6	77.3	79.0	77.5	75.9	79.5	77.0
Volume Mbb1/CD	72.13	59.63	58.92	71.37	40.64	40.22	64.26
Lead CC/USG	2.20	1.93	1.32	2.24	3.00	1.17	2.71
Sulfur ppm	187	424	438	373	350	492	170
<b>Composition LV%</b>							
BTX raffinate	2.0	2.4	2.4	2.0	3.5	1.0	2.2
Butanes	7.0	7.2	7.1	6.8	7.1	7.4	7.3
90 RON reformat	50.4	32.2	19.0	40.3	40.1	20.2	55.9
100 RON reformat	--	--	6.8	--	--	2.8	--
Cat cracker gasoline (untreated feed)	16.5	38.4	41.0	26.2	24.0	44.7	9.1
Alkylate	--	--	5.2	--	--	6.4	--
Light hydrocrackate	1.8	--	--	2.0	--	--	--
Isomerized light naphtha	17.6	--	--	--	--	--	--
Natural gasoline	4.7	--	--	5.0	--	--	5.8
Straight run	--	19.8	18.5	17.7	25.3	17.5	19.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0

(Continued)

TABLE 6.3-3. Continued

Cluster: East Coast - Region 2	Year							
	1977			1980			1985	
	A	B	C	A	B	C	A	B/C
Scenarios								
Lead-free pool								
Research octane clear	92.0	92.0	93.8	92.0	93.5	93.5	92.0	93.8
Motor octane clear	84.0	84.0	84.0	84.0	84.0	84.0	84.0	84.0
Volume Mbbl/CD	8.88	34.23	33.82	3.35	64.79	64.15	2.22	106.91
Sulfur ppm	459	3	136	5	369	317	5	394
Composition LV%								
BTX raffinate	--	--	--	--	--	--	--	0.1
Butanes	8.2	7.5	6.9	7.2	7.8	7.4	6.6	7.3
90 RON reformat	22.6	24.4	2.7	11.0	--	--	--	--
95 RON reformat	--	8.7	--	37.7	--	--	46.5	--
100 RON reformat	--	19.1	50.3	--	28.9	34.9	--	30.9
Cat cracker gasoline (untreated feed)	30.2	--	13.2	--	34.0	28.3	--	34.6
Alkylate	29.5	18.9	4.6	25.2	15.6	12.9	25.1	12.1
Light hydrocrackate	--	9.1	7.7	0.6	4.3	3.9	--	2.1
Isomerized light naphtha	--	--	--	--	0.9	4.8	--	6.8
Natural gasoline	9.5	12.3	12.4	18.3	6.5	6.6	21.8	3.9
Straight run	--	--	2.2	--	2.0	1.2	--	2.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total gasoline pool								
Research octane clear	88.0	88.8	90.7	88.0	89.9	91.7	88.0	93.8
Motor octane clear	79.7	80.3	81.6	79.7	81.0	82.5	79.7	84.0
Volume Mbbl/CD	110.97	110.42	109.11	111.52	109.82	108.72	110.79	106.91
Lead CC/USG	2.24	1.49	0.94	2.42	1.23	0.47	2.77	--
Sulfur ppm	343	315	324	387	376	369	387	394

- Catalytic Reforming Unit (CRU),
- Fluid Catalytic Cracking Unit (FCCU),
- Alkylation Unit, and
- Isomerization Unit.

A literature search was performed to determine the operating energy requirements of the above, and the results are presented in Table 6.3-4.

In addition to the normal range of energy consumption for each unit, it was necessary to determine the incremental energy required to make a process change, such as increasing reformer severity from 90 to 100 or increasing the conversion on the FCCU. On the CRU, literature yielded correlations from which the increase in reactor temperature required to increase product octane (or severity) from 90 to 100 could be calculated (LI-151, GA-182). A heat and material balance was then performed to determine the amount of fuel needed to provide the higher reactor temperatures.

Increasing reformer severity from 90 to 100 results in a decreasing yield of gasoline. The lower yield of gasoline per barrel of naphtha charged means that more naphtha must be processed to produce the same volume of gasoline. Increasing the rate of naphtha charged necessitates the addition of more catalytic reformer, isomerization, and alkylation capacity. The fuel required to process the additional naphtha is considered a primary energy penalty. Typical yield-severity relationships are illustrated in Figure 6.2-1.

TABLE 6.3-4. UTILITY REQUIREMENTS

Unit	Type of Energy	Fuel (Oil or Gas) MBTU/bbl.			Steam lbs./bbl.			Electricity kWhr/bbl.		
		Max.	Min.	Avg.	Max.	Min.	Avg.	Max.	Min.	Avg.
Catalytic Reforming Unit		400	200	308	85	0	25	6.0	0.7	3.4
Fluid Catalytic Cracking		350	0	100	92	-73	-30	6.0	0.2	1.8
Alkylation		1070	0	410	950	0	425	8.8	0.5	4.0
Isomerization		684	50	100	65	25	35	4.6	1.0	1.5

Sources: RA-119, GA-182, DI-070, BL-078

Process changes were also necessary on the FCCU's, primarily in the form of increased conversion, which is defined as the volume percent of the feedstock that is converted to gasoline and lighter components. This helps in three ways:

- The higher reactor temperatures necessary to achieve higher conversion cause an increase in the octane of the cracked gasoline.
- More cracked gasoline is produced, which helps offset the yield loss on the CRU.
- More reactive propylene and butylene are produced, which can be converted to high octane gasoline by alkylation.

These benefits are balanced by an increase in the catalytic coke yield, which typically ranges from five to seven weight percent of the feed. All of this coke is burned off in the regenerator providing process heat for the reactor section and usually making steam by waste heat exchange or in a CO Boiler. That portion of the heat liberation from coke burning that goes to increased process heat plus the incremental heat loss in flue gas out the stack can be considered an energy penalty. Typically, a 10 volume percent increase in conversion will cause an increase in coke yield of 0.9 weight percent of the feed (GA-182).

Once the above two steps were completed, it was merely necessary to multiply the energy consumption factors determined in step two by the processing changes called for in step one. The sum of the penalties for each process was then recorded in Form 5, Appendix B.

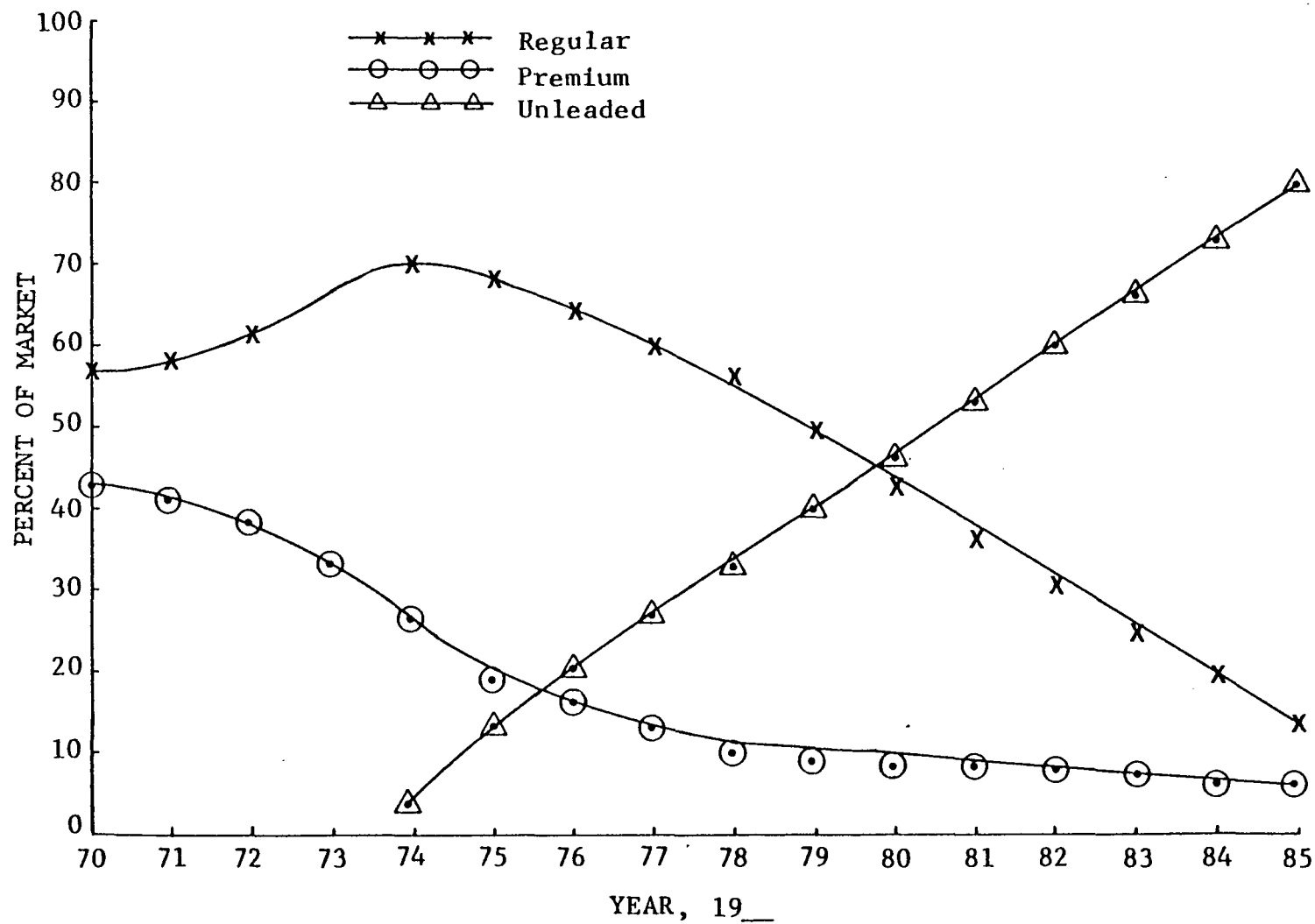
It was determined that there was no energy penalty applicable to lead phasedown in 1974. While considerable expenditures of capital funds had been made to prepare for unleaded gasoline production by that time, the demand in 1974 was so low that no pool clear octane increase was required. This can be easily understood by examining Figure 6.3-1, which shows gasoline consumption by grades (AA-022). It can readily be seen that the decrease in market share of leaded premium gasoline, which began with the introduction of lower compression ratios in new cars in 1971, far outweighed the impact of unleaded gasoline in 1974. In fact it is not until 1978 that the combined premium and unleaded market reaches the level of leaded premium in 1970, at which time the clear pool octane requirement begins to increase rapidly. Thus, it can be said that the production of unleaded gasoline caused no energy penalty in 1974.

The only clear alternative to increased processing severity is the use of a non-lead additive, probably MMT. Calculations for such an eventuality were made using reported MMT susceptibility data (UN-072, BA-459). These data indicated that a two to three octane number improvement could be achieved by adding 0.125 grams per gallon of MMT to the typical unleaded blend. This effect was used to offset part of the processing severity, and the application of energy consumption factors was then identical to the above cases.

#### 6.3.6 Water-Engineering Calculation Methodology

The wastewater control techniques used in 1974 or projected to be used in 1980 or 1985 which result in energy penalties include primary, secondary, and tertiary treatment. A description follows of how the energy penalties associated with each of these control systems was calculated.

Figure 6.3-1. Gasoline Consumption by Grades





Primary level wastewater treatment for refineries was assumed for this study to include sour water strippers, oil-water separators, and dissolved air flotation units. Sour water stripping and dissolved air flotation requires energy. The use of oil-water separators, however, results in a net energy recovery since the oil separated in the units is recycled back to the refinery for processing. The energy requirements for sour water stripping were calculated from data reported in the literature (KL-032). Credit for the energy recovered (as steam) from the processing in Claus plants of the recovered  $H_2S$  from the strippers is accounted for in the desulfurization calculations. The estimated energy penalty for sour water stripping is 3.2 million Btu per  $10^3$  barrels of refinery throughput. For dissolved air flotation the energy requirement calculated from literature data is 104,000 Btu per  $10^3$  barrels of refinery throughput (PR-121). The oil water separator results in a recovery of 770,000 Btu per  $10^3$  barrels of refinery throughput based on calculations made from literature data (EN-407). The net energy penalty of primary level wastewater treatment is calculated to be 2.5 million Btu per  $10^3$  barrels of refining capacity. This number includes wastewater pumping costs.

Secondary level wastewater treatment was assumed to include, in addition to primary level treatment, equalization, coagulation, flocculation, and carbonaceous waste removal. Carbonaceous waste removal could be trickling filters, unaerated lagoons, aeration towers, aerated lagoons, or activated sludge. Based on literature data the energy penalty for equalization is 162,000 Btu per  $10^3$  barrels refinery throughput. For coagulation and flocculation it is 16,200 Btu per  $10^3$  barrels throughput. The energy requirements for carbonaceous waste removal depend upon what process is used. Both trickling filters and unaerated lagoons require no energy. From literature data the energy

requirement for aeration towers was calculated to be 30,000 Btu per  $10^3$  barrels and for activated sludge the requirement is 240,000 Btu per  $10^3$  barrels (PR-121).

Tertiary level wastewater treatment includes, in addition to secondary level treatment, activated carbon adsorption and wastewater flow reduction. The reduction in wastewater flow results in a net energy savings since less water is treated per barrel of crude throughput. An average flow of 32.5 gallons of wastewater per barrel of crude throughput was assumed for primary and secondary treatment plants. For tertiary treatment a flow of 20 gallons per barrel was assumed (EN-407). Activated carbon adsorption requires approximately 20,000 Btu per  $10^3$  barrels of crude throughput according to literature data (PR-121). This does not include regeneration of the carbon. Since the adsorption system would operate as a polishing step, regeneration of the spent carbon would not be economical.

#### 6.4 Regionalization

The energy penalties are regionalized because they are calculated from regionalized data. Regional regulations were applied to regional refinery configurations in order to develop the necessary control strategies. The energy consumption of these control strategies were determined on a per barrel basis, which could then be converted to a regional total by applying the regional crude running projections.

#### 6.5 Allocation Among Fuel Types

The allocation of the calculated energy penalties among the fuel types was straightforward. The present and projected shortages of natural gas make it very doubtful that this

fuel could assume additional load. Therefore, it must naturally be assumed that fuel oils will provide the additional process heat, as well as energy to generate any incremental steam requirements. It was assumed that any additional electricity would be purchased rather than self-generated. The tremendous capital necessary to build power plants would be difficult to generate in this time frame when refiners will be hard pressed to meet the demands of environmental improvement as well as energy independence.

Some energy penalties (or credits) were expressed in terms of catalytic coke when they involved changes on the Fluid Catalytic Cracking Units. Since this self-generated fuel must be burned in the FCC Regenerator, it is unique and not interchangeable with other fuel sources.

## 7.0

### SUMMARY OF RESULTS

This section summarizes the results of the primary energy penalty calculations described in Section 6.0 for the years 1980 and 1985. The penalties are totaled for Census Regions 1 through 9 according to the six pollutants considered--particulates,  $\text{NO}_x$ ,  $\text{SO}_2$ , HC, lead, and wastewater. Three cases were evaluated. They were chosen to represent the minimum, maximum, and most likely energy penalties due to projected and existing federally enforceable regulations for the subject years. Summaries of each of these three sections follow.

## 7.1

### Minimum Energy Penalty Case

The results of the minimum penalty case for 1980 and 1985 are presented in Table 7.1-1. The numbers for the minimum penalty case for each pollutant were generated from the energy penalty data on the Form 5's in Appendix B. For each region and each pollutant the control strategy mixes and regulatory scenarios with the lowest energy requirements were totalled. The numbers for that region for each pollutant were then added to the other eight regional numbers for each pollutant to give the totals shown in Table 7.1-1.

Table 7.1-1 shows that lead control is the largest energy consumer of the pollutants covered in the minimum penalty case. For 1980 lead control is approximately 49 percent of the total energy penalty and about 2 percent of the total daily refinery energy consumption. For 1985 lead control accounts for slightly over 58 percent of the total daily energy penalty and over 3 percent of the total daily refinery energy consumption. The projected baseline daily energy consumption for the refining industry for 1980 is  $11.65 \times 10^{12}$  Btu/day and  $13.43 \times 10^{12}$  Btu/day for 1985.

TABLE 7.1-1. MINIMUM ENERGY PENALTIES  
REGIONS 1-9

Pollutant	1980 Minimum Energy Penalty (10 <sup>6</sup> Btu/day)	Percent of 1980 Baseline Energy Consumption (%)	1985 Minimum Energy Penalty (10 <sup>6</sup> Btu/day)	Percent of 1985 Baseline Energy Consumption (%)
Particulates	404	0.003	487	0.004
NO <sub>x</sub>	407	0.003	512	0.004
SO <sub>2</sub>	127,880	1.097	154,178	1.148
HC	6,570	0.056	8,044	0.060
Lead	248,550	2.133	439,173	3.270
Water	<u>121,855</u>	<u>1.046</u>	<u>151,880</u>	<u>1.131</u>
TOTAL PENALTY	505,666	4.338	754,274	5.617

## 7.2 Maximum Energy Penalty Case

The results of the maximum penalty case for 1980 and 1985 are presented in Table 7.2-1. Data from the Form 5's in Appendix B were used to generate the numbers for the maximum penalty case. For each region and each pollutant the control strategy mixes and regulatory scenarios with the largest energy requirements were totalled. Then the numbers for that region for each pollutant were added to the other eight regional numbers for each pollutant to give the totals shown in Table 7.2-1.

Table 7.2-1 shows that SO<sub>2</sub> control is the largest energy consumer of the pollutants covered in the maximum penalty case. For 1980, SO<sub>2</sub> control is roughly 67 percent of the total daily energy penalty and about 9 percent of the daily refinery energy consumption. For 1985, SO<sub>2</sub> control accounts for approximately 59 percent of the energy penalty and is equivalent to almost 10 percent of the daily refinery energy consumption. The projected baseline daily energy consumption for the refining industry for 1980 is  $11.65 \times 10^{12}$  Btu/day and  $13.43 \times 10^{12}$  Btu/day for 1985.

## 7.3 Most Likely Energy Penalty Case

The results of the most likely energy penalty case for 1980 and 1985 are presented in Table 7.3-1. Data from the Form 5's in Appendix B were used to generate the numbers for the most likely penalty case. For each region and each pollutant, the control strategy mixes and regulatory scenarios judged to be the most likely case for 1980 and 1985 based on available information were totalled. Then the numbers for that region for each pollutant were added to the other eight regional numbers for each pollutant to give the totals shown in Table 7.3-1.

TABLE 7.2-1. MAXIMUM ENERGY PENALTIES FOR 1980 AND 1985  
REGIONS 1-9

Pollutant	1980 Maximum Energy Penalty (10 <sup>6</sup> Btu/day)	Percent of 1980 Baseline Energy Consumption (%)	1985 Maximum Energy Penalty (10 <sup>6</sup> Btu/day)	Percent of 1985 Baseline Energy Consumption (%)
Particulates	11,171	0.096	12,738	0.095
NO <sub>x</sub>	2,406	0.021	2,760	0.021
SO <sub>2</sub>	1,091,977	9.373	1,319,781	9.827
HC	6,587	0.057	8,066	0.060
Lead	376,173	3.229	745,378	5.550
Water	145,040	1.245	161,283	1.201
TOTAL PENALTY	1,633,354	14.021	2,250,006	16.754

TABLE 7.3-1. MOST LIKELY ENERGY PENALTIES FOR 1980 AND 1985  
REGIONS 1-9

Pollutant	1980 Most Likely Energy Penalty (10 <sup>6</sup> Btu/day)	Percent of 1980 Baseline Energy Consumption (%)	1985 Most Likely Energy Penalty (10 <sup>6</sup> Btu/day)	Percent of 1985 Baseline Energy Consumption (%)
Particulates	416	0.004	504	0.004
NO <sub>x</sub>	560	0.005	852	0.006
SO <sub>2</sub>	375,269	3.221	495,413	3.689
HC	6,570	0.056	8,044	0.060
Lead	362,320	3.110	662,590	4.934
Water	<u>145,040</u>	<u>1.245</u>	<u>161,283</u>	<u>1.201</u>
TOTAL PENALTY	890,175	7.641	1,328,686	9.894



Table 7.3-1 shows that SO<sub>2</sub> control is the largest energy consumer for the most likely penalty case in 1980. SO<sub>2</sub> control is 42 percent of the total energy penalty for that year and is equivalent to a little over 3 percent of the daily refinery energy consumption for 1980. For 1985, lead control is the largest energy consumer for the most likely case. Lead control is almost 50 percent of the total energy penalty for the most likely case for 1985 and is equal to about 5 percent of the daily refinery energy consumption. The projected baseline daily energy consumption for the refining industry for 1980 is  $11.65 \times 10^{12}$  Btu/day and  $13.43 \times 10^{12}$  Btu/day for 1985.

## 8.0 SECONDARY IMPACT INDICATORS

For this study secondary energy penalties were classified as either recurring or non-recurring impacts. Recurring impacts are those linked to materials consumed during the operation of a pollution control system, such as catalyst or chemicals. Non-recurring secondary impacts refer to the one-time energy costs of materials which go into the manufacture of a control system as well as the energy expended in its construction. Actual determination of the secondary energy penalties associated with the environmental controls mentioned in Section 6.0 was beyond the scope of this study. Instead, indicators of the secondary penalties were provided. The remainder of this section discusses the secondary impact indicators developed for each pollutant.

### 8.1 Particulate Secondary Impact Indicators

In calculating the secondary impact indicators for the control of particulate emissions there were two non-recurring impacts and two recurring impacts. Also included were three descriptive impacts, that is, indicators of FCC throughput, number of FCC units in operation, and particulate collection efficiency for the control strategy mix under consideration.

The two non-recurring impacts are those associated with the actual process units (*i.e.*, the electrostatic precipitator or wet scrubber). The two recurring impacts were ammonia requirement for ESP feed conditioning and make-up water for wet scrubbing. Assuming that 45% of the operating electrostatic precipitators need conditioning with ammonia (average concentration of 25 moles  $\text{NH}_3/10^3$  moles feed gas), then a base figure for the ammonia requirement is 1.12 lb  $\text{NH}_3/\text{MMscf}$ . For wet

scrubbing, the make-up water base figure was assumed to be 51.35 gal H<sub>2</sub>O/MMscf (MA-519). From these two base figures and data on FCC throughput, the recurring impacts for control of particulate emissions can be readily calculated.

## 8.2 Sulfur Dioxide Secondary Impact Indicators

In calculating the secondary impact indicators for the control of sulfur dioxide there were seven non-recurring impacts and seven recurring impacts. All secondary impact indicators were determined according to equipment throughputs.

All seven non-recurring impacts represent new or additional capacities for various process units. All capacities quoted are annual incremental throughputs for a specified region except for the FCC flue gas scrubber. Since the FCC scrubber was the only process unit unique to a region (as determined by bbl FCC feed/bbl crude charged), it seemed appropriate to quote the average size of a scrubber. To determine annual incremental throughputs for a region, production data for that region (see Appendix B, Form 2) and FCC flue gas base rates of 99,167 scfm (wet basis) and 78,973 scfm (dry basis) were used (DA-069). Note also that annual incremental throughputs for Claus units and SCOT units are identical. This is a common sizing practice as reflected in technical literature.

All the recurring impacts represent catalyst and chemical requirements for various process units. All seven recurring impacts are annual figures and were calculated according to Table 8.2-1.

TABLE 8.2-1. CHEMICAL AND CATALYST REQUIREMENTS FOR SO<sub>2</sub> CONTROL

	(lb/unit)
Catalyst	
Distillate HDS (bbl)	0.001
Gas Oil/FCC Feed HDS (bbl)	0.0021
Residual Oil HDS (bbl)	0.5
Scot Unit (ton Sulfur)	0.11
Chemicals	
Amine (MMscf Feed)	2.5
Diisopropanol Amine (MMscf Feed)	2.5
Scrubber Liquor (MMscf)	8.33 (gal)

References: AD-033, MA-519, PF-008

### 8.3 NO<sub>x</sub> Secondary Impact Indicators

The control of NO<sub>x</sub> emissions from fuel combustion in refineries by flue gas recirculation results in a non-recurring secondary impact. Two-stage combustion does not require the use of any additional control systems and so has no secondary impact associated with it. There are no recurring impacts associated with either flue gas recirculation or two stage combustion.

The secondary impact of flue gas recirculation is the material requirement for the equipment needed to recirculate a portion of the flue gas back through the burners.

### 8.4 Hydrocarbon Secondary Impact Indicators

The control of hydrocarbons from tank car/truck loading racks, oil-water separators, vapor blowdown, and storage tanks results in significant non-recurring secondary impacts. There are no recurring impacts associated with the control of these sources.

For tank car/truck loading rack control, the secondary impact indicators chosen are the material requirements for the vapor collection system and vapor recovery unit. For oil-water separator control the secondary impact indicators are the floating covers required for the separator. The secondary impact indicators used for vapor blowdown control are the piping and associated equipment for blowdown collection and the flares used to combust the hydrocarbon vapors. For storage tank control the secondary impact indicators are the pressure tanks and floating roofs used. Appendix B, Form 6, Regulatory Scenarios 15 through 18 present the secondary impact indicators for 1974, 1980, and 1985.

#### 8.5      Lead Secondary Impact Indicators

The removal of lead additives from motor gasoline can be compensated for by increased processing severity as detailed in Section 7.2. Part of this increased severity must come through the construction of more Catalytic Reformers, Isomerization Units, and Alkylation Units. The required additional capacity for each of these was tabulated as a one time secondary impact in Form 6 of Appendix B.

There are also recurring requirements for chemicals and catalyst associated with the new capacity, and increased consumption rates on existing units due to more severe processing conditions. The major substances involved are:

- Catalytic Reformer - reforming catalyst,  
HDS catalyst
- Isomerization - catalyst, and

- Alkylation - sulfuric acid, hydrofluoric acid, and caustic.

In addition to these, a recurring requirement for MMT is projected for Control Strategy Mix No. 2. Balancing all of these is a credit due to the decreasing demand for lead alkyls. The requirements of all the above are tabulated in Form 6, Appendix B.

#### 8.6 Water Secondary Impact Indicators

The control of refinery wastewater discharges by secondary or tertiary level treatment results in significant non-recurring secondary impacts. Only tertiary level wastewater treatment results in a recurring secondary impact.

The facilities used for secondary level wastewater treatment were mentioned in Section 6.2.6. The secondary impact indicators chosen for secondary wastewater control were the number of treatment plants controlled at this level within a region as well as their combined wastewater throughput.

The facilities used for tertiary level wastewater treatment were mentioned in Section 6.2.6, also. The secondary impact indicators chosen for tertiary level treatment were the number of treatment plants controlled at this level within a region as well as their combined wastewater throughput. Tertiary wastewater treatment also has a recurring secondary impact. The activated carbon adsorption unit requires that makeup carbon be supplied periodically. The indicator chosen was the number of tons of carbon consumed per year per region.

## 9.0 DISCUSSION

This section discusses changes in three variables which might increase or decrease the energy penalty due to environmental regulations for the petroleum refining industry. The impact of these variables on the energy penalties calculated in this report cannot be quantified because of limitations in the scope of work. Therefore, a qualitative discussion is presented on these three variables: possible changes in the refining industry makeup; possible changes in environmental regulations; and possible changes in environmental control methods.

### 9.1 Possible Changes in the Refining Industry Makeup

There are several trends in the petroleum refining industry that are concerned with maintaining environmental quality, conserving energy, and meeting consumer demands. A brief description of these changes and a discussion of their effects on the energy penalties follows.

A major trend has been toward an increasing dependence on foreign crude oils which generally contain a higher percentage of sulfur than domestically produced oil. To meet federal and state SO<sub>2</sub> emission standards, improved methods of hydrodesulfurization and sulfur recovery are being developed. These sulfur bearing crudes also tend to be corrosive, consequently many processing modifications are necessary before most domestic refineries can handle the high sulfur crudes. The result of having to install hydrodesulfurization and sulfur recovery equipment is an increase in both primary and secondary energy penalties for the refining industry.

Another refining industry change is the direct result of the federally imposed schedule for lead phasedown in gasoline. Expansion of processing units which produce high octane blending stocks, such as alkylation and catalytic reforming units, may be anticipated to meet the demand for unleaded gasoline. Although polymerization is another process capable of producing high octane blending stocks, it will probably be of little significance, since olefins have become an increasingly important petrochemical feedstock. The result of this change will be an increase in both primary and secondary energy penalties.

Still another industry change is the utilization of improved catalysts. These new catalysts are of the bimetallic variety and have been found to be more active and more selective. Furthermore, a special oxidation catalyst for catalytic crackers has been developed. This catalyst enables a greater conversion of CO to CO<sub>2</sub> at lower temperatures. Through better oxidation, there is a decrease in the coke laydown on the catalyst resulting in a higher product yield. This change results in improved efficiencies and better yields for refineries.

## 9.2 Possible Changes in Environmental Regulations

Changes in federally enforceable environmental regulations will have a direct impact on the energy penalties of the refining industry. Of course, a change of regulation which requires more efficient pollutant removal usually results in larger energy penalties. One such recent change proposed by the EPA at the end of 1976 required more stringent SO<sub>2</sub> control for new, modified, or reconstructed refinery sulfur recovery plants. However, this control will result in a net energy recovery equal to approximately 90,000 barrels of fuel oil yearly, the EPA reports. Another potential change in environmental regulations is one requiring reduced sulfur levels in



all fuel oil products from refineries. This regulation would require additional hydrodesulfurization capacity and would result in larger primary and secondary energy impacts for refineries.

The potential also exists for more stringent NO<sub>x</sub> emissions standards being proposed for fuel combustion units in refineries. This would certainly result in increased energy penalties for refineries, especially if flue gas scrubbing is required.

Changes in water regulations are also taking shape and will almost certainly impact the refining industry. Beginning in September, 1978 and ending no later than December, 1979 is a phased schedule of proposed toxic effluent regulations which will be published by the EPA. Control of specific toxic pollutants in refinery effluents will be mandated. Their control will probably result in larger primary and secondary energy penalties for refineries. Compliance will be required of all existing sources by June 30, 1983.

### 9.3 Possible Changes in Control Methods

Control technology is continuously evolving with systems being developed that more efficiently remove pollutants which are subject to regulation. Many of these systems have application to pollution abatement in the refining industry or were developed specifically for refinery use. Their application in refineries may or may not result in increased energy consumption. Below is a discussion of these systems and whether or not increased energy consumption will result from their use.

#### 9.3.1 Particulates Control Changes

Wet scrubbers and fabric filters both have potential for particulate removal from cat-cracker flue gas. At least one refinery source currently employs wet scrubbers on an FCC unit. Breakthroughs in fabric filter design may open the door for their application to particulate removal from FCC flue gases. Both control systems result in primary and secondary energy penalties.

#### 9.3.2 SO<sub>2</sub> Control Changes

Possible changes for SO<sub>2</sub> control methods for refineries include hydrodesulfurization and flue gas scrubbing. While hydrodesulfurization will probably be extensively employed in the near future by refineries, flue gas scrubbing has an uncertain future. It has good potential, but requires more development to make it a reliable control. Both of these SO<sub>2</sub> control methods result in higher energy penalties.

#### 9.3.3 NO<sub>x</sub> Control Changes

Currently NO<sub>x</sub> control in the refinery industry relies on combustion modification techniques. Possible changes in this control method due to more stringent NO<sub>x</sub> standards could mean implementation of flue gas scrubbing systems. Similar to SO<sub>2</sub> flue gas scrubbing, certain obstacles concerning operating reliability face this technology. Energy penalties would be larger if this control system were used.

#### 9.3.4      Hydrocarbon Control Changes

A major control change for hydrocarbons in the future will probably be design and installation of efficient blowdown recovery systems. Significant reductions in hydrocarbon blowdown losses to flares can be realized by a well designed collection and routing system. This control would result in lower energy penalties for refineries since less flare operation would be needed and more product could be recovered.

#### 9.3.5      Lead Control Changes

Non-lead additives to gasoline which could replace tetra-ethyl lead as an octane promoter would result in significant energy penalty savings for the refining industry. A magnesium based additive is currently being investigated and looks attractive on an economic basis. Its environmental impact is also being examined.

#### 9.3.6      Water Control Changes

Refinery wastewater control currently centers on gravity separation followed by secondary biological oxidation. Carbon adsorption systems will be included in refinery effluent control by 1983. Other wastewater controls which may have potential for refinery effluent treatment include reverse osmosis, electrodialysis, and ion exchange. All of these systems would result in larger energy penalties for refineries. However, the energy penalty from the use of these tertiary control techniques would be minimized because of wastewater flow reduction schemes which must be implemented by 1983.

## 10.0 CONCLUSIONS AND RECOMMENDATIONS

This section presents the conclusions of this study, discusses conservation opportunities for refineries, and recommends areas of further study related to energy penalties from air and water pollution regulation.

### 10.1 Conclusions

The following is a list of conclusions based on the results which were presented in Section 7.0. Also, presented after the conclusions is a brief discussion of energy conservation opportunities. A comparison of the magnitude of the energy penalties and energy conservation potential for the refining industry for 1980 and 1985 is included in the discussion.

- For 1980 the largest contributors to the total "Most Likely" energy penalty are SO<sub>2</sub> control and gasoline lead reduction. They contribute 42 percent and 41 percent of the total, respectively.
- For 1985 the largest contributors to the total "Most Likely" energy penalty are SO<sub>2</sub> control and gasoline lead reduction, again. They contribute 37 percent and 50 percent of the total, respectively.
- Regulatory stringency has a significant effect on the energy penalties for the petroleum refining industry. The maximum case total energy penalties for 1980 and 1985 are about 3 times as large as the minimum case total penalties.

## 10.2 Refinery Conservation Opportunities

The refining industry is one of the largest energy consumers of the major U.S. industries. There are numerous energy conservation opportunities within refineries. Equipment whose modification could result in significant conservation opportunities within refineries include fired heaters, heat exchangers, air coolers, pumps and drivers, compressors, fractionating towers, vacuum systems, and steam systems (EC-011). Table 10.2-1 presents an example breakdown of energy consumption in a refinery (GO-152).

TABLE 10.2-1. EXAMPLE REFINERY ENERGY CONSUMPTION BREAKDOWN

Source	Percent of Total (%)
Direct Fired Fuel in Process Heaters	78
Electrical Energy	11
Steam	10
Cooling Water	1

Proper conservation can reduce refinery energy consumption by as much as 10 to 15 percent (EC-011). Therefore, based on numbers used in this study conservation may recover from 60,000 to 90,000 Btu per barrel of crude processed. This compares to the "Most Likely" energy penalties of 50,000 Btu per barrel for 1980 and 60,000 Btu per barrel for 1985. This comparison indicates that for refineries the energy penalties due to environmental regulations are roughly equivalent to the energy recovery available from using conservation techniques.

### 10.3      Recommendations

Recommended areas of further work center on obtaining more detailed pollution control equipment information, both existing and projected, for the refining industry. The primary sources of data for this report were articles, journals, and reports published by governmental agencies and the refining industry. The accuracy of the resulting penalty numbers could probably be improved if a survey of the refining industry's current and projected pollution abatement equipment and planned installations were completed.

### CONVERSION FACTORS

The references used in developing this report generally stated flows, capacities, weights, etc., in English measurement units. The following table can be used to convert these measurements to metric units.

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
Btu	kcal	0.252
bbl	ℓ	159.0
gal	ℓ	3.785
ton	kg	907.2
lbs	kg	0.454
cm	in	0.394
ft <sup>3</sup>	m <sup>3</sup>	0.0283
psi	kg/cm <sup>2</sup>	14.223
g/gal	g/ℓ	0.264
Btu/bbl	kcal/ℓ	0.0016
kWh/bbl	kWh/ℓ	0.0063
lb/bbl	kg/ℓ	0.0285
lb/10 <sup>6</sup> Btu	g/Mcal	18.0
grain/ft <sup>3</sup>	g/m <sup>3</sup>	2.29
gal/MMcf	ℓ/(hm) <sup>3</sup>	133.7

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