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Volume 1 (of 2 Volumes)

REGISTRY

Refinery Siting Workbook

Appendices A & B

Published July 1980

Prepared for:
U.S. Department of Energy
Assistant Secretary for Resource Application
Office of Oil and Natural Gas, Resource Application
Under Contract No. DE-AC01-79RA33001

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Prepared for:
U.S. Department of Energy
Assistant Secretary for Resource Application
Office of Oil and Natural Gas, Resource Application
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PREFACE

This Workbook was prepared to assist Federal, state and local government agencies to reach timely decisions regarding refinery sitings, modifications or expansions, when proposed by industry, by providing background information relative to making such decisions.

The Resource Applications Office (RA) of the Department of Energy had the Workbook prepared because RA has a strong interest in ensuring that U.S. refinery capacity meets U.S. petroleum products demands, that it is capable of using increasing amounts of heavy, high sulfur content crude oils as refinery inputs, and that it can provide the unleaded gasoline and low sulfur fuels needed to meet environmental requirements.

The Workbook consists of two volumes. The first volume contains basic refinery information such as descriptions of typical refinery configurations and process units, refinery investment requirements, land needs, refinery construction and operating personnel requirements, applicable environmental regulations and permitting needs, and the socio-economic effects of refinery construction and operation.

The second volume refers to the reference materials used in the preparation of the Workbook. It is intended to assist those seeking more detailed information on items covered in the first volume.

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ACKNOWLEDGEMENTS

This report was prepared by Mittelhauser Corporation of Downers Grove, Illinois, and El Toro, California. The principal investigators were Thomas W. Barrs, Carl S. Kelley, III, Harry J. Takach, and W. Thomas Atkins. The efforts of our secretarial staff are sincerely appreciated.

Panuzio Associates of Washington, D.C., prepared the permit survey forms and the state and local permit tabulations. Mr. David South of the Mittelhauser staff contributed the socioeconomic information. Mr. G. R. Moss reviewed the technical refinery descriptive material. Messrs. Stephen P. Chamberlain and M. J. Karlowicz of the API Washington staff provided review comments on several report sections and Richard Drew for the slides. We would like to thank the many petroleum companies, refinery and regulatory staff who provided first-hand data on the technical, regulatory, and permitting sections.

Project management at the Department of Energy, Office of Oil and Natural Gas, Resource Applications was under the direction of Messrs. F. V. Marsik and E. L. Peer.

The regulatory and permitting information was complete and accurate as of completion of the draft report, February, 1980.

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1.0 INTRODUCTION

1.1 BACKGROUND

The siting of new industrial plants, like petroleum refineries, is a complex issue because of the increasing amount of regulatory and permitting activities that must be considered by both the governmental agencies and the refiner. There is increased public concern and participation in issues that can affect the environmental and physical characteristics of a local area.

In recent years, there have been over thirteen petroleum refinery projects scheduled for the East Coast that have been cancelled for environmental reasons. Reasons for cancellation included the adoption of new state laws that prohibited coastal refinery sites, city council disapproval, rejection by the state environmental agencies, and in several cases opposition by local voters. It is quite possible that some of these cancellations could have been avoided if the state and local government officials and citizens were provided with a detailed description of a petroleum refinery and its direct and indirect impacts upon their local community, and the refinery had a better understanding of the respective regulatory and permitting requirements and bases.

The compilation of a refinery siting workbook addressing the technical and socio-economic issues, regulatory concerns and permitting activities would allow local officials to present a reasonable picture of the impacts associated with refinery construction and operation to their constituents. This workbook would either verify facts offered by the refining company or establish a basis for asking additional questions from this pre-existing knowledge of the refinery industry.

A parallel benefit from this workbook would be to provide the refining company with an understanding of federal, state, and local environmental regulations, permitting, and reporting requirements for a new refinery or an expansion or major modification of an existing refinery. This information would be extremely valuable to the small, independent refiner who does not have the large, full-time legal and engineering staffs required to maintain proficiency in these dynamic, evolving areas.

1.2 OBJECTIVE AND SCOPE

The objective of this effort is to develop and provide basic refinery-related information for use by state and local government officials as a basis for establishing responsible refinery siting requirements and policies consistent with the federal clean air and water standards and socio-economic concerns. The report will be organized into two volumes. The main text comprises the basic topics of physical concerns, regulatory requirements, and permitting activities, while the second volume includes the detailed appendix materials such as the applicable laws and the necessary permits as available and a glossary of pertinent terms.

As a means to this objective, three refinery sizes, 200,000, 100,000 and 30,000 barrels per day crude charge will be discussed in technical terms. Process unit configuration will be presented which will maximize either gasoline or heating oil production with either sweet or sour crude oil feedstocks. Discussions will be directed to the ten (10) refinery cases shown below. The two cases not discussed in detail are considered not to be viable in most instances for the configuration and size classification.

Crude Feed Rate, Barrels/Day	Maximum Gasoline		Maximum Fuel Oil	
	Sweet Crude Oil	Sour Crude Oil	Sweet Crude Oil	Sour Crude Oil
200,000	x	x	x	x
100,000	x	x	x	x
30,000			x	x

The major issues affecting the socio-economic impact of siting the refinery in a given locale will be presented. These data will review the factors affecting the human environment and the issues that must be addressed to assess the impact that a refinery will have on a community.

The key federal registrations which impact upon a refinery siting decision shall be reviewed. Summaries of these regulations and a simplified decision diagram for the air and water acts shall be presented to assist both government and refinery officials in understanding the scope of regulatory impact.

All pertinent procedures required for refinery permitting shall be reviewed under the generalized headings of air, water, health and safety, land use, and miscellaneous permits. This categorization at the federal, state and local levels of government shall be used as a basis for establishing degrees of emphasis. Literature and personal contacts were used to obtain permit information at all levels of government. Surveys were conducted at the state and local levels to assist the contacting and compilation of pertinent permits.

The report shall also address both new refinery construction and major refinery modification or expansion. Where this distinction is important in the regulatory and permitting phases, it shall be noted and discussed.

1.3 PROJECT APPROACH

The workbook is presented under three major sections. These are refinery descriptions stressing unit concepts and physical concerns, regulatory requirements, and permitting activities.

1.3.1 Refinery Description

There are many ways to define a refinery. Its purpose and flexibility are determined by the type of crude, design basis, and market needs among other factors. In order to provide the local or state government representative faced with refinery decisions in their community with an understanding about the performance and impacts from such a facility, it is important to define key terms such as crude oil and refinery configuration and list the general technical assumptions.

Crude oil is a mixture of compounds composed of carbon and hydrogen called hydrocarbons, and various amounts of sulfur, nitrogen, oxygen, trace metals, and water. The physical characteristics of a given crude oil can range from an almost clear liquid, similar to gasoline, to a pitch that is so viscous it must be heated to be pumped. Crude oil from geographically related oil fields tends to have similar compositions and properties.

Crude oils are typically designated as being sweet or sour and light or heavy. In addition, they are classified as being paraffin, intermediate, or naphthene based. For the purposes of this workbook, sweet and sour crude oils are defined according to the total sulfur content of the crude oil. While the refining industry has various definitions of sweet and sour crude oil, sweet crude oil refers to crude oil containing 0.5% or less of total sulfur (by weight). Sour crude oil contains more than 0.5% total sulfur.* Likewise in this workbook, light crude oil is defined as having an API gravity of greater than 25. Likewise, heavy crude oil has an API gravity of 25 or less. The crude oil base depends upon the predominant type of hydrocarbon present. For example, extremely light crude oil (API gravity greater than 40) is generally paraffin based. Crude oils with API gravity between 40 and 25 are intermediate based, and crude oils with API gravity less than 25 are generally naphthene based. The vast majority of crude oils produced are of intermediate or naphthene bases.

The hydrocarbons present in crude oils may be separated by distillation into various fractions. While a fraction may contain many different hydrocarbon compounds, each fraction has the distinction of boiling within a specific temperature range. Lighter crude oils will produce a large proportion of fractions that have lower boiling points (light fractions)

*See Section 3.1.1 for a more detailed discussion of sweet and sour crude oil.

and heavier crude oils will have a large proportion of fractions that boil at higher temperatures (heavy fractions). It is these fractions that are further processed into the final products. By varying process conditions, and unit processes, many different fractions can be produced, depending upon the final product requirements.

Of the non-hydrocarbon compounds present in crude oil, sulfur is the material of principal concern. Sulfur may be present as dissolved, free sulfur, hydrogen sulfide, or as organic sulfur compounds such as mercaptans. Generally, heavier crude oils will have higher sulfur concentrations, but sweet, heavy crude oils do exist. Other sulfur compounds, like hydrogen sulfide, may also be formed during the various refining processes. Sulfur compounds can cause severe corrosion to process units and can be a major source of air pollution.

The nitrogen and oxygen can also cause corrosion of process units and the nitrogen can also form ammonia which can cause violation of the wastewater discharge regulations. The trace metals, such as arsenic, nickel, and vanadium, may be present in such concentrations that they are poisons to certain process catalysts. The properties of the crude oil are all considered when deciding upon the overall refinery design basis.

The purpose of an oil refinery is to process the crude oil into its various fractions and then refine and blend those components to form the desired finished products. A refinery consists of a number of modules or units, each with a specific purpose, integrated into a processing sequence. The actual refinery configuration and size will depend upon the characteristics of the crude oil and the desired final product mix. Product mix is highly dependent on the market for the various products. Theoretically, it is possible to produce virtually any petroleum product from any crude oil. Thus, heavy crude oils may be used to produce lighter products such as gasoline. However, economics play an important role in refining and it is more economical to use lighter crude oils for producing lighter products. Therefore, a refinery will be designed to make maximum use of the expected range of crude oil characteristics.

While most refineries have flexibility as to the types of crude oils that can be processed, a significant change in the crude oil characteristics may result in reduced production of certain products or necessitate major process and equipment modifications. For example, a refinery designed to process sweet crude oil may be incapable of processing sour crude oil due to (1) the metallurgy of the equipment may not be able to handle the corrosion caused by the sulfur present, and (2) the facilities may not exist to handle the increased sulfur removal requirements. Similarly, a refinery designed to produce gasoline from light crude oil may not be able to maintain gasoline production if it switches to heavy crude oil, due to a decrease in the gasoline components present in the crude oil and the lack of facilities to convert the heavier crude oil into lower boiling fractions. Therefore, the decisions as to the type of refinery and the process sequence or configuration to be employed is heavily dependent upon the expected characteristics of the crude oil and the economics of processing the crude oil into the various products.

Due to the requirements of the refining operations, a barrel of crude oil does not become a barrel of product available for sale. This is not to imply inherent inefficiency. Factors such as the generation of light ends which are used for refining fuel and the use of a portion of certain petroleum fractions as feedstocks for internal refinery uses such as in hydrogen manufacturing or as fuel results in approximately 95% of the initial barrel of crude oil becoming finished, saleable product. If a large amount of cracking and reforming is required, such as in the production of unleaded gasoline, a greater amount of light ends are produced and the overall recovery would be lower than the 95%. Similarly, if fuel oil is the major product, overall recoveries are higher due to the less severe processing conditions.

The remaining parts of this section detail the overall characteristics of example refineries of various capacities processing sweet and sour crude oil. One example refinery maximizes gasoline production while the other maximizes the production of fuel oil. These example refinery configurations are shown in Figures 1-4, and explained in detail in Section 3.1. The process units required to produce a certain product mix do not change with design throughput. Therefore, these four figures characterize the process sequence for the ten refinery discussion cases. It should be emphasized that there is no "typical" refinery; however, example refineries are offered in this document for illustrative purposes. While actual refineries will have similar types of units, some may be deleted and the overall configuration may be modified. The basic unit descriptions presented in Section 2 will, however, still be applicable. Data presented in Section 3 include:

- Costs of refinery construction cases
- Required utilities, labor and land
- Wastes generated and pollution control methods
- Noise and physical appearance
- Socio-economic impacts.

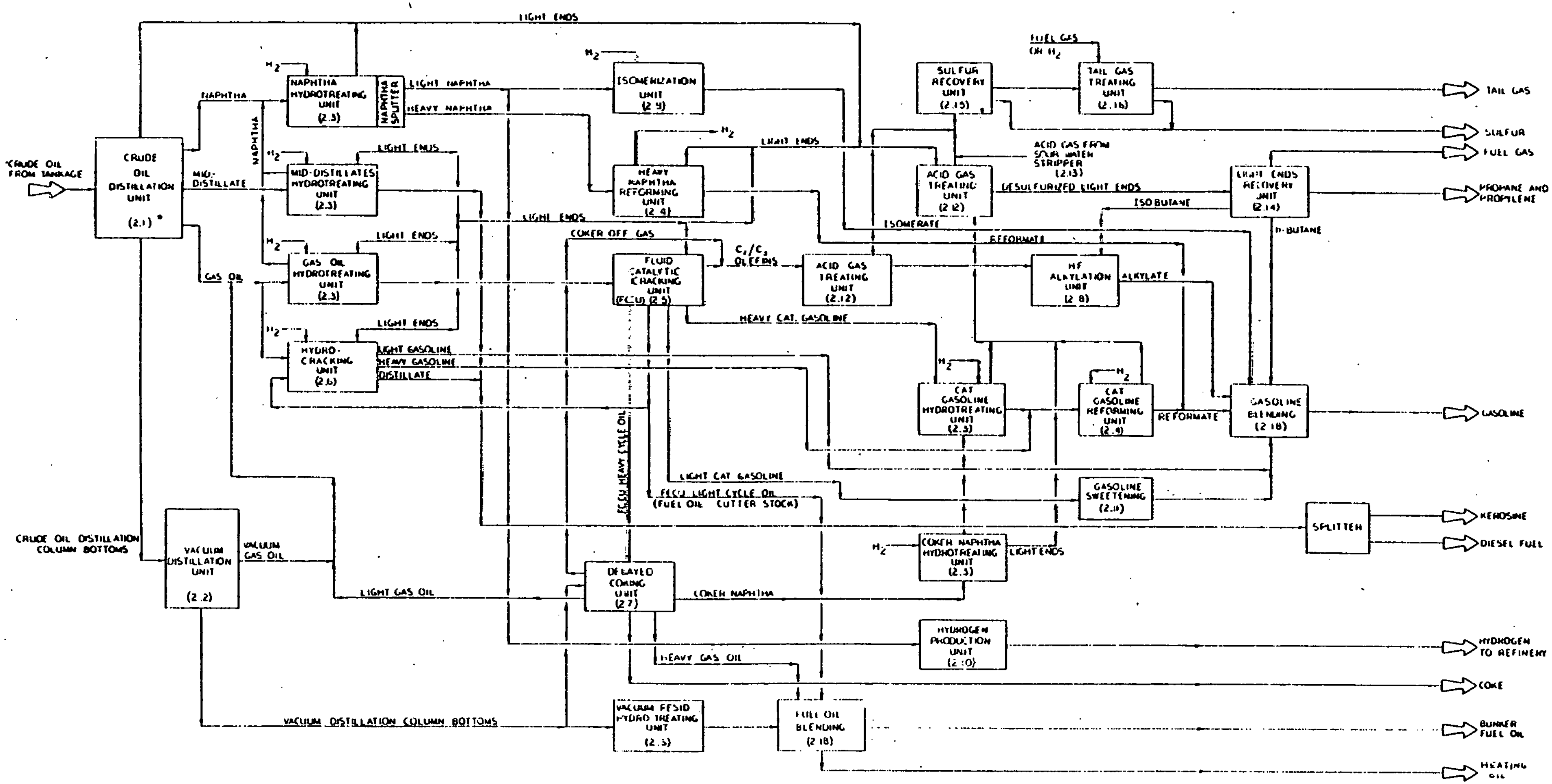
1.3.2 Regulatory Requirements

There are three federal regulations which have a major impact upon refinery siting, construction, modification or expansion planning and decisions. These are:

- National Environmental Policy Act
- Clean Air Act
- Federal Water Pollution Control Act.

Summaries of these regulations and a simplified decision diagram are presented in Section 4.0 to assist both government and refinery officials in understanding regulatory impacts on refinery siting and expansion considerations. Following these summary items, a review of the legislation highlighting the specific areas pertinent to refinery activity is developed. The law, or sections thereof, and other relevant material is tabulated in the Appendix.

FIGURE 1
GASOLINE REFINERY SOUR CRUDE OIL



* INDICATES REPORT SECTION WHERE PROCESS UNIT IS DESCRIBED

FIGURE 2
GASOLINE REFINERY SWEET CRUDE OIL

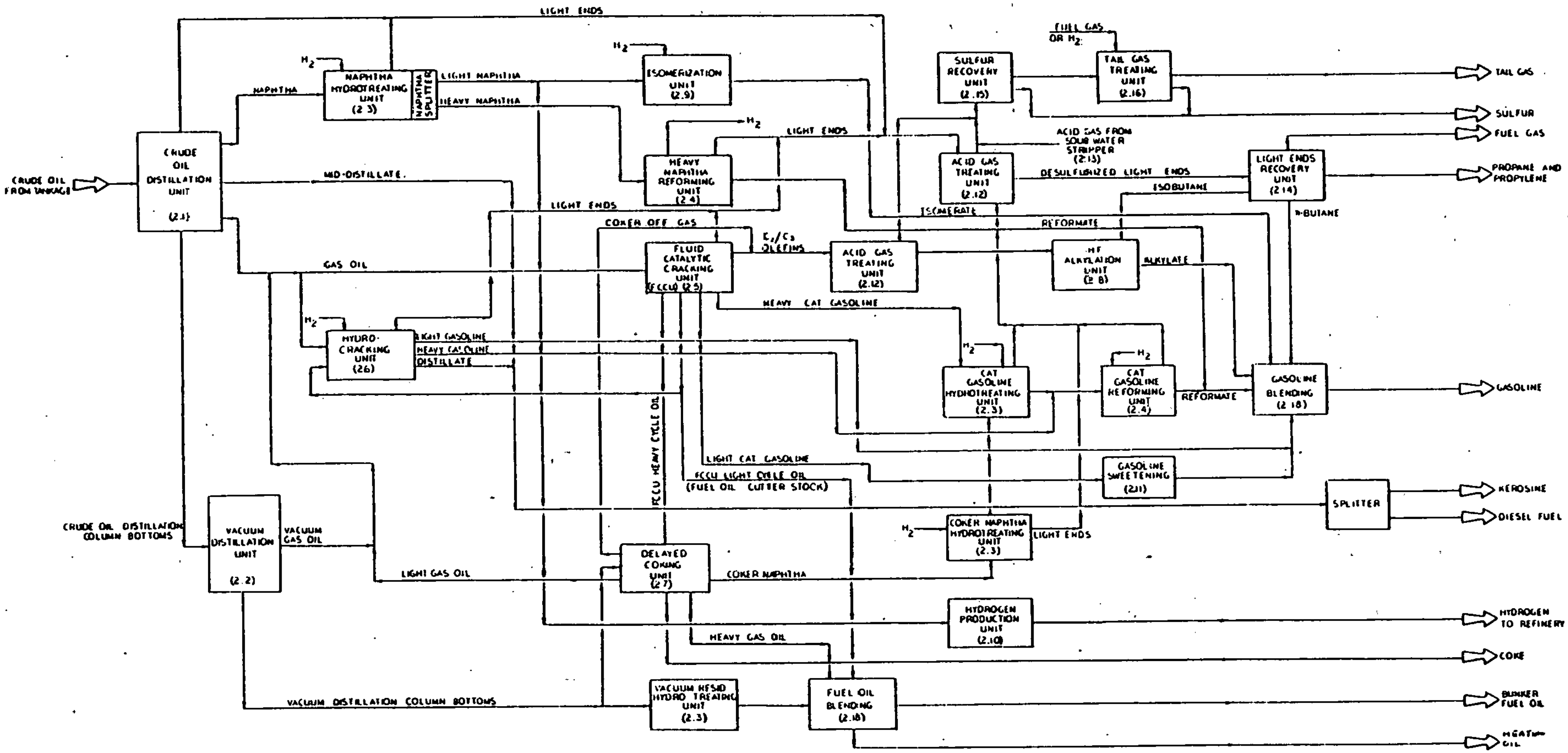


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FIGURE 3
FUEL OIL REFINERY SOUR CRUDE OIL

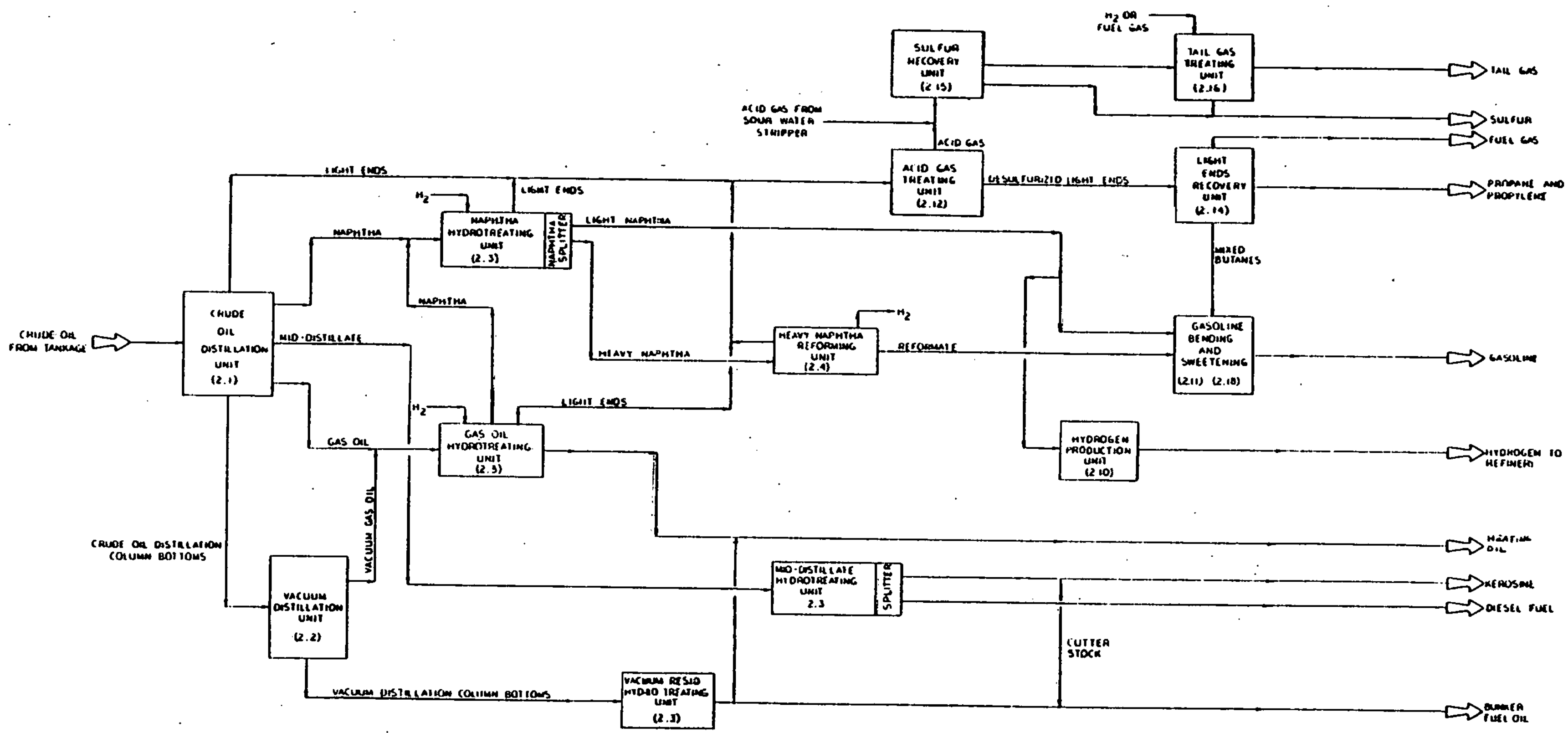
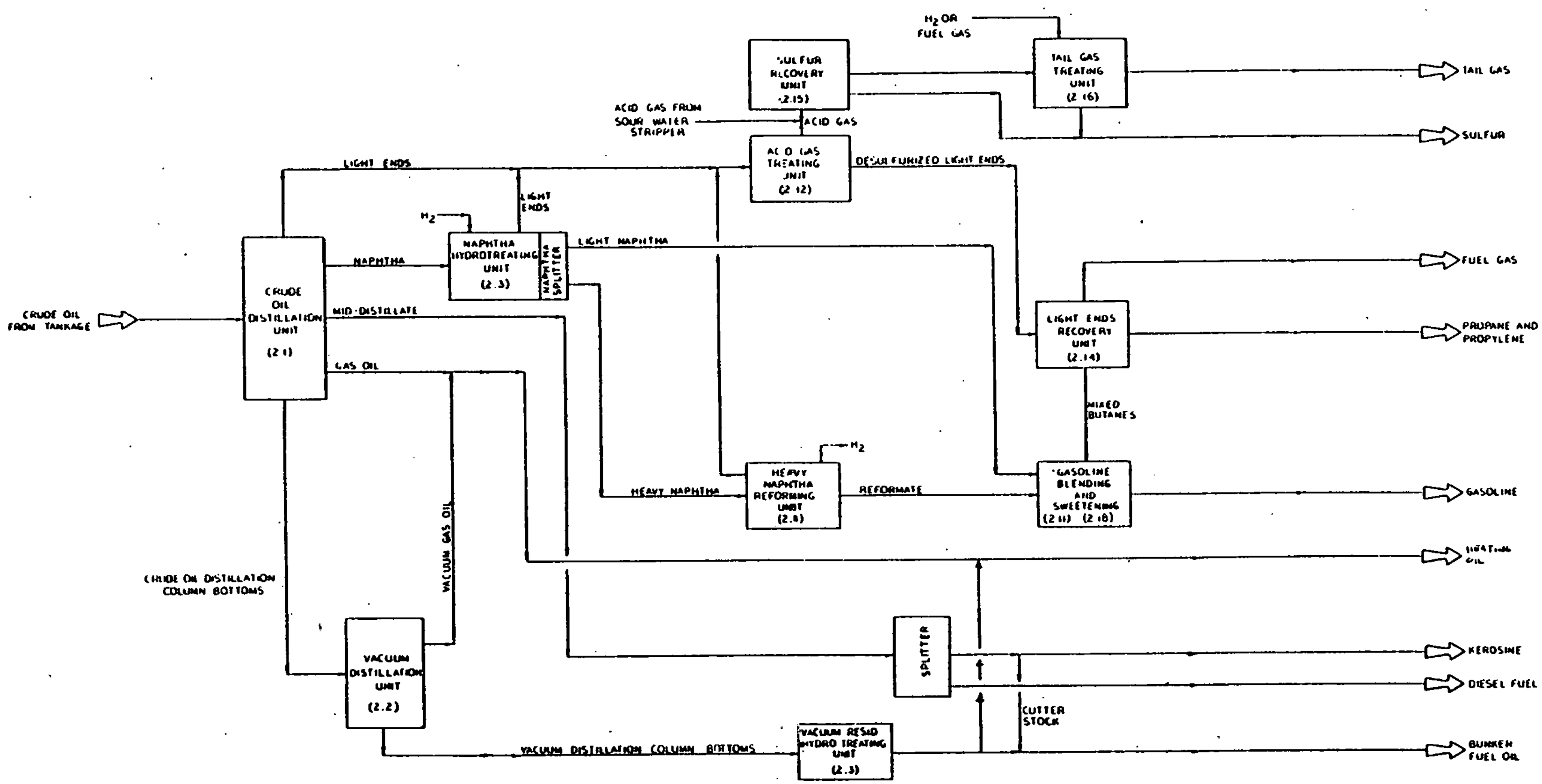


FIGURE 4

FUEL OIL REFINERY SWEET CRUDE OIL



Lesser regulations, with respect to refinery siting, such as the Resource Conservation and Recovery Act, Toxic Substances Control Act, Endangered Species Act, Wild and Scenic River Act, will be briefly mentioned and summarized as necessary. One of these acts often plays a significant role in refinery siting but only at the site specific level. With the general approach for this workbook, detailed development does not appear warranted.

1.3.3 Permitting Activity

The permitting requirements (Section 5.0) of the federal, state, and local levels were reviewed from the literature, personal contacts, and mailed surveys. Successful, unsuccessful, and presently pending applications for siting refineries were considered to identify issues and concerns by each level of government. This effort established the areas emphasized in the permitting section.

At the federal level, agencies were contacted who have processed refinery siting permits to discuss major concerns and obtain background documents relating to specific siting attempts. A list of federal permits required has also been compiled and placed in the Appendix of this workbook with as many of the required forms as possible to show both government and petroleum industry officials the level of information required.

At the state level, we contacted, by mailed questionnaire, each state to learn specific requirements for refinery siting. The letter contained a research format enclosure requesting the states to tabulate the permitting requirements. In these letters, care was exercised so as not to imply that specific siting plans were represented. Response was mixed and frequent follow-up requests were needed.

A table was prepared to summarize the primary permit review agencies for all 50 states. The agencies are presented under the following general permit-granting headings:

- Air
- Water
- Health and Safety
- Land Use
- Miscellaneous.

At the local level, the permitting activity is quite variable. Since there are but a relatively few areas throughout the country with refinery experience, a survey technique was adopted in an attempt to cover all types of local refinery experience. A research questionnaire was sent to all localities identified in a recent Department of Energy report who have refinery permit activity in the last five years to determine if any procedures were established as a result of the application. Second, a similar questionnaire was sent to cities with populations of 100,000 or more to determine the range of procedures and preparations. Finally, of 26 cities were sent a questionnaire who may add further depth to questionnaires were sent to 26 select cities who might add further depth to the survey or have pertinent refinery permit exposure due to past actions or location.

Representative tables were developed under the general permit headings listed above for the local permitting process. Ten to fifteen example cities are listed from the survey responses under each of the five titles. Cities with refinery experience or from the select list should generally be preferred. The tables were developed along the lines of listing the form of local government, refinery experience status, and other significant parameters to aid the report reader identify cities with parallel refinery experience as the one under specific consideration.

2.0 PROCESS UNIT DESCRIPTIONS

2.1 CRUDE OIL DISTILLATION UNIT

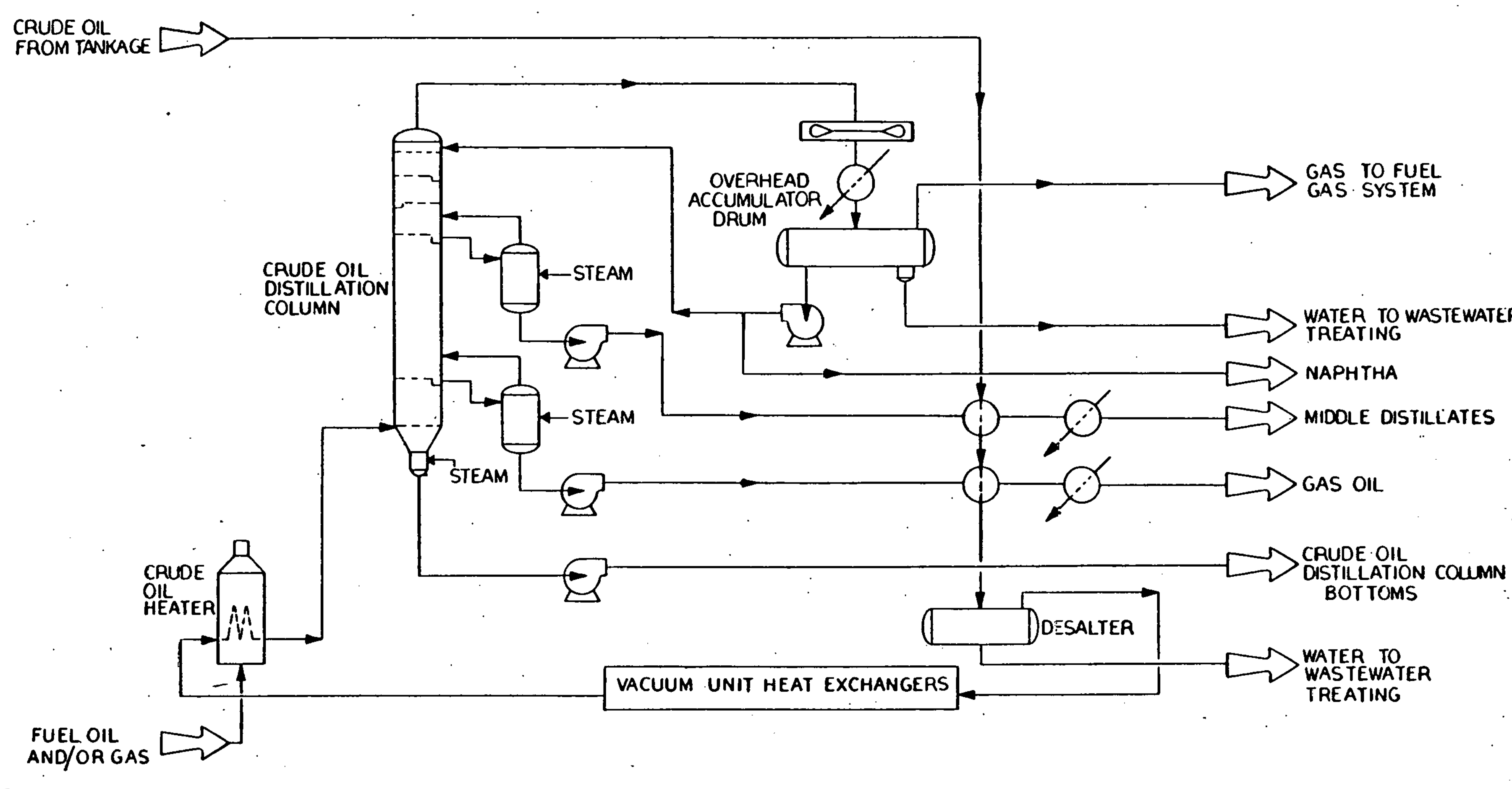
The crude oil distillation unit is normally the first refinery unit to process the crude oil. In this unit, distillation serves as the basic method for separating the crude petroleum into various fractions that can then be refined into final products.

As shown in Figure 5, the crude oil is pumped from tankage, preheated by heat exchange with various product streams (fractions) to about 200-250°F and sent to the desalter. The purpose of desalting is to remove inorganic salts from crude oil so that these salts will not cause plugging of exchangers, coking of furnaces and corrosion. The process also removes the soluble trace metals present in the water phase which act as poisons to process catalysts. The most widely used desalting process is electrostatic desalting. In this process, chemicals and water are added to the crude oil and oil/water separation is carried out by gravity differential in the presence of a high voltage electrostatic field. The field helps to agglomerate the water droplets, which contain the salts, and thus separate the water from the oil. The oil is removed from the top of the desalter vessel, and the water from the bottom. The water is sent to the wastewater treatment plant.

The crude oil is then pumped through additional heat exchangers at the vacuum unit and then through the crude oil furnace where the oil is further heated to 650-700°F. The hot crude oil is then fed to the crude oil distillation column commonly known as the atmospheric distillation column. This column is typically a cylindrical tower 10 to 30 feet in diameter and can be up to 100 feet high and operates at 5 to 20 psig.

As shown in Figure 5, the column separates (distills) the crude oil into product streams having specific boiling point ranges. The higher the boiling point, the "heavier" the fraction. Depending upon the subsequent refinery process scheme, these streams commonly are light ends (lowest boiling points), naphthas, middle distillates, gas

FIGURE 5
CRUDE OIL DISTILLATION UNIT



oil, and crude oil unit residuum (highest boiling point). Some of the heavier streams are often individually steam stripped to further remove the light material that may still be present after distillation. The amount of each fraction depends upon initial composition of the crude oil and the operating conditions of the tower. (A lighter crude oil will produce a greater proportion of light fractions.)

Following distillation, the crude oil distillation unit product streams can be further processed by a number of schemes. For example, distillates can be separated by further distillation to make finished products such as diesel fuel, kerosene and jet fuel. Gas oils can be cracked to form lighter, lower boiling compounds which may be blended into gasolines or recovered directly as heating oil. The processing scheme chosen is dictated by the quality of the crude oil available and the demands of the geographical area where the products are to be marketed.

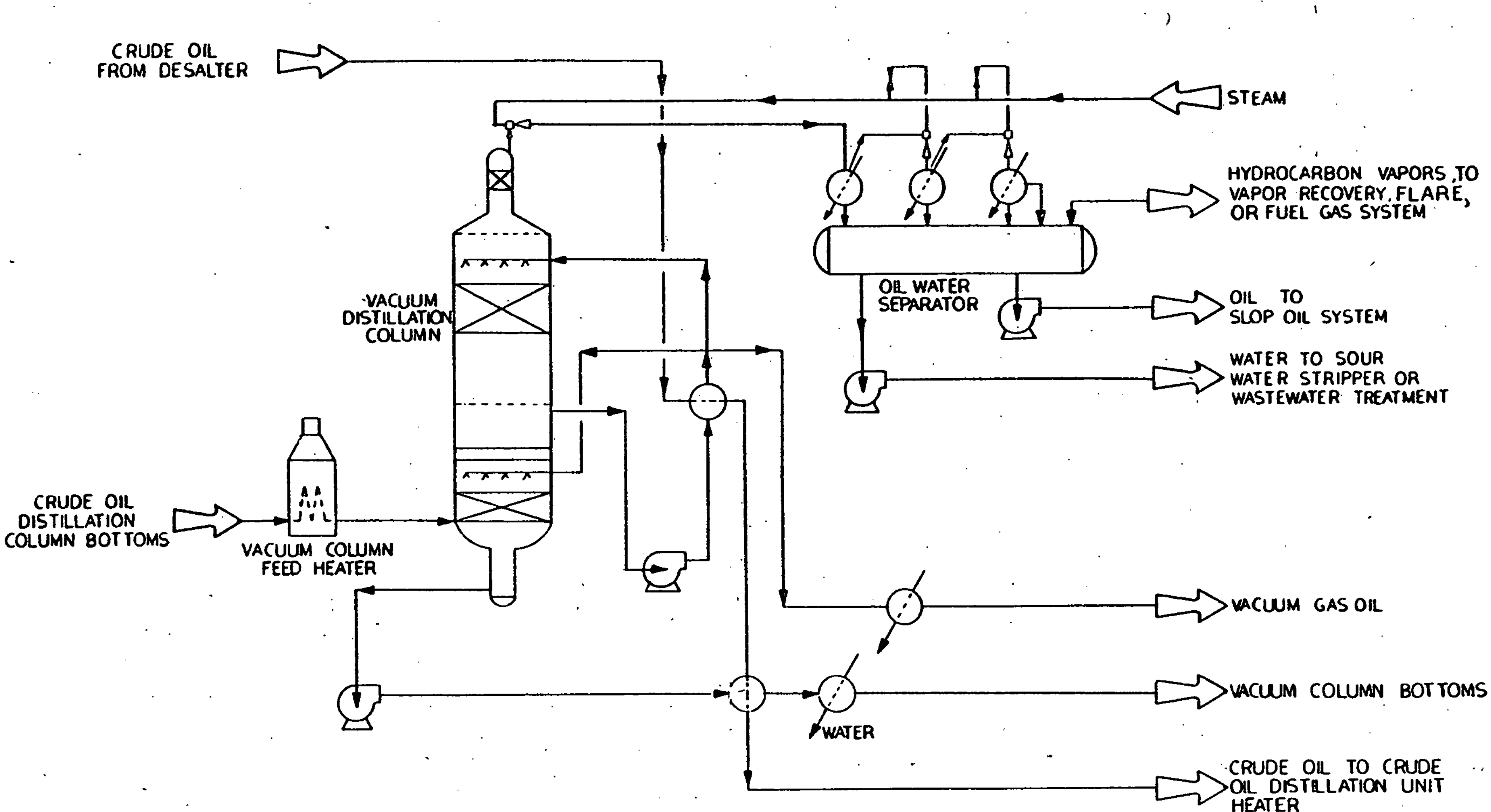
2.2 VACUUM DISTILLATION UNIT

A vacuum distillation unit is shown in Figure 6. The feed to this unit is the bottoms from the crude oil distillation column. The hot feed is first heated in a furnace to 700-750°F and then charged to the vacuum distillation column. This column operates at 735-660 mm Hg vacuum (760 mm Hg is atmospheric pressure).* The vacuum in the column can be produced by using steam ejectors or vacuum pumps. (Figure 6 shows steam ejectors.) The combination of high temperature and reduced pressure causes additional distillation to take place which cannot occur at atmospheric pressure.

The product streams from the vacuum tower typically are light vacuum gas oil, heavy vacuum gas oil, and vacuum tower bottoms. The tower also produces a stream of lighter material which commonly is collected as an overhead product oil. This oil typically is sent to the "slop oil" collection system. This recovered "slop" oil can be reprocessed through the crude oil distllation unit or sent to other oil processing units.

*mm Hg = millimeters of mercury.

FIGURE 6
VACUUM DISTILLATION UNIT



The product streams from the vacuum distillation unit can be further processed depending upon the desired products and the sulfur content of the crude. While the vacuum gas oil product can be sent to hydrocracking or catalytic cracking, it may be recovered directly as heating fuel oil and would not require further processing. The vacuum column bottoms, in addition to being sent to the coker, may also be sent to the fuel oil blending where it is recovered as bunker fuel oil. If a low sulfur bunker fuel oil is required, the vacuum bottoms may be desulfurized prior to blending.

2.3 HYDROTREATING UNIT

Hydrotreating (also known as hydrodesulfurization) is a catalytic process used to remove sulfur, nitrogen, olefins, arsenic and lead from liquid petroleum fractions. Typically, hydrotreating units are employed ahead of such processes as catalytic reforming since the catalyst used in reforming will be rendered inactive if the feed contains sulfur, nitrogen, olefins or metals. Hydrotreating may also be used prior to catalytic cracking to reduce the sulfur emissions from the regenerator and improve product yields. It may also be employed to upgrade petroleum fractions into finished products such as kerosene, diesel fuel and heating oil. Hydrotreating generally removes over 90% of the above contaminants.

Sulfur removal is accomplished by contacting the untreated petroleum fractions with hydrogen in the presence of a catalyst. The reaction converts the sulfur to hydrogen sulfide (H_2S) and the nitrogen to ammonia (NH_3). The H_2S and NH_3 are separated from the liquid fraction by vapor-liquid separation. In addition, there will be some saturation (removal) of olefins which also will consume hydrogen. The degree of olefin saturation will depend upon the severity of the hydrotreating.

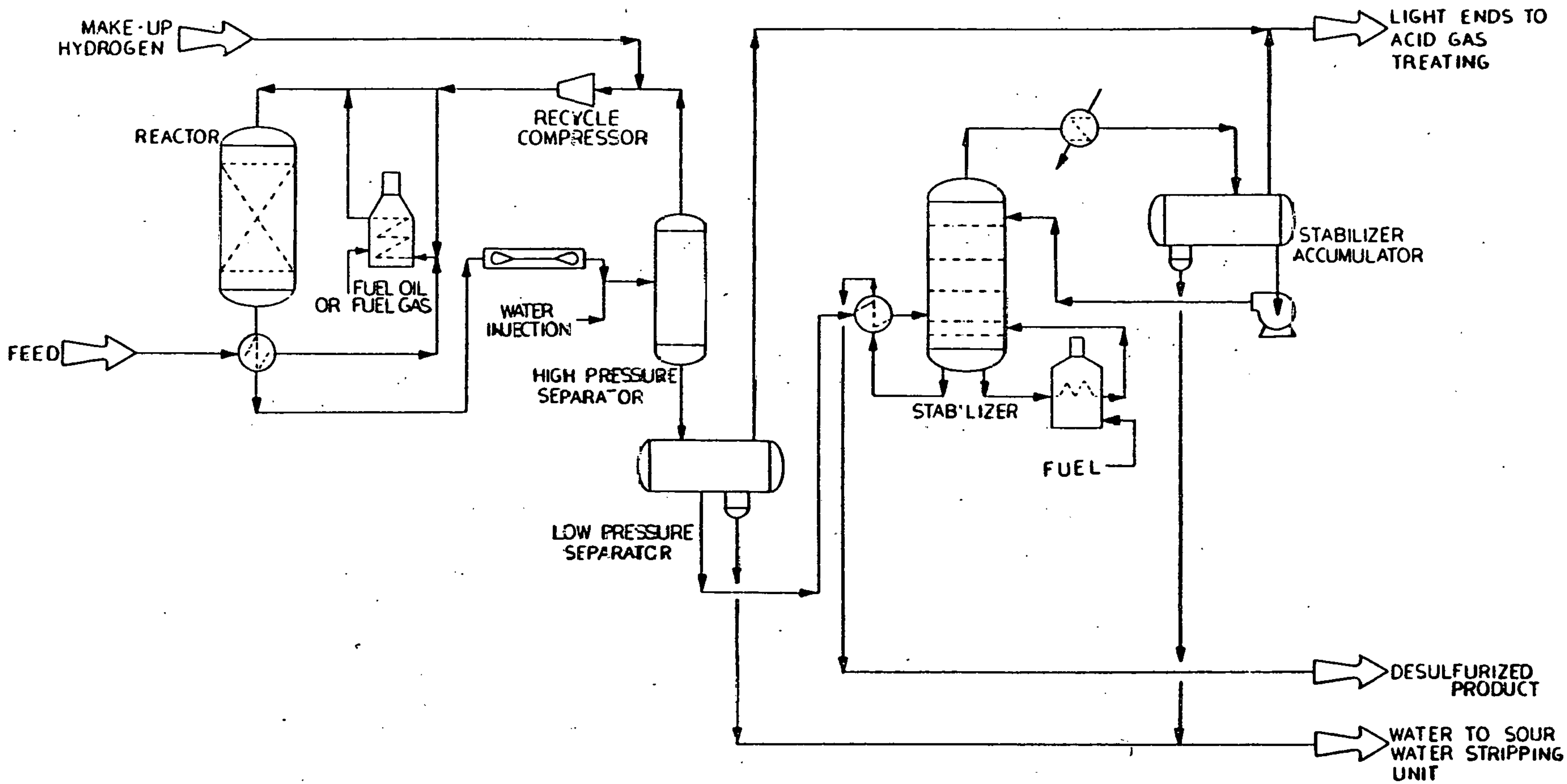
Hydrotreating processes are used on a wide range of feedstocks from naphthas to heavy residual oils (see Figures 1 and 2). In general, hydrotreating of process streams from sour crude oil requires greater quantities of hydrogen and more severe operating conditions (higher hydrogen pressures and lower space velocities) than does hydrotreating of sweet crude oil fractions. The hydrotreating of the heavier process streams (such as distillates or resid) consumes more hydrogen than does the treating of the lighter streams (such as naphtha).

Periodically, the hydrotreating unit catalyst loses activity due to the deposition of coke on the catalyst particles, and must be regenerated. Regeneration consists of burning off this coke under controlled conditions. Typically, regeneration is required when the cumulative amount of feedstock processed is equivalent to about 100-200 barrels of oil/lb of catalyst. This is dependent upon the amount of sulfur present, the characteristics of the feedstock, and the severity of the operating conditions. In many refineries hydrotreating catalysts are regenerated every one to three years.

Figure 7 shows a typical hydrotreating process. The feed is mixed with fresh makeup and recycled hydrogen, heated, and fed to the catalytic reactor where the sulfur and nitrogen are converted to H_2S and NH_3. The hydrogen required for the desulfurization is supplied by the catalytic reforming unit and (if required) a hydrogen plant.

The product then goes to the high pressure separator where the excess hydrogen is flashed off and recycled to the reactor. The liquid then passes to the low pressure separator where the H_2S, NH_3, non-condensible gases, and additional hydrogen are removed. The gas from the low pressure separator is treated to remove the H_2S, and the treated gas goes to the fuel gas treating system. The liquid product from the low pressure separator is then fed to a stabilizer where the remaining light material is stripped off and sent to the fuel gas system and the liquid product goes to further processing or storage. The product from naphtha hydrotreating is sent to a naphtha splitter (fractionation) where the light and heavy naphtha streams are separated. Heavier hydrotreated fractions (i.e., gas oils) can be sent to cracking operations for further processing, or recovered as final products.

FIGURE 7
HYDROTREATING UNIT



For catalyst regeneration, some refineries provide swing reactors that can be taken out of service for catalyst regeneration and therefore do not require a shutdown to regenerate the catalyst.

2.4 CATALYTIC REFORMING UNIT

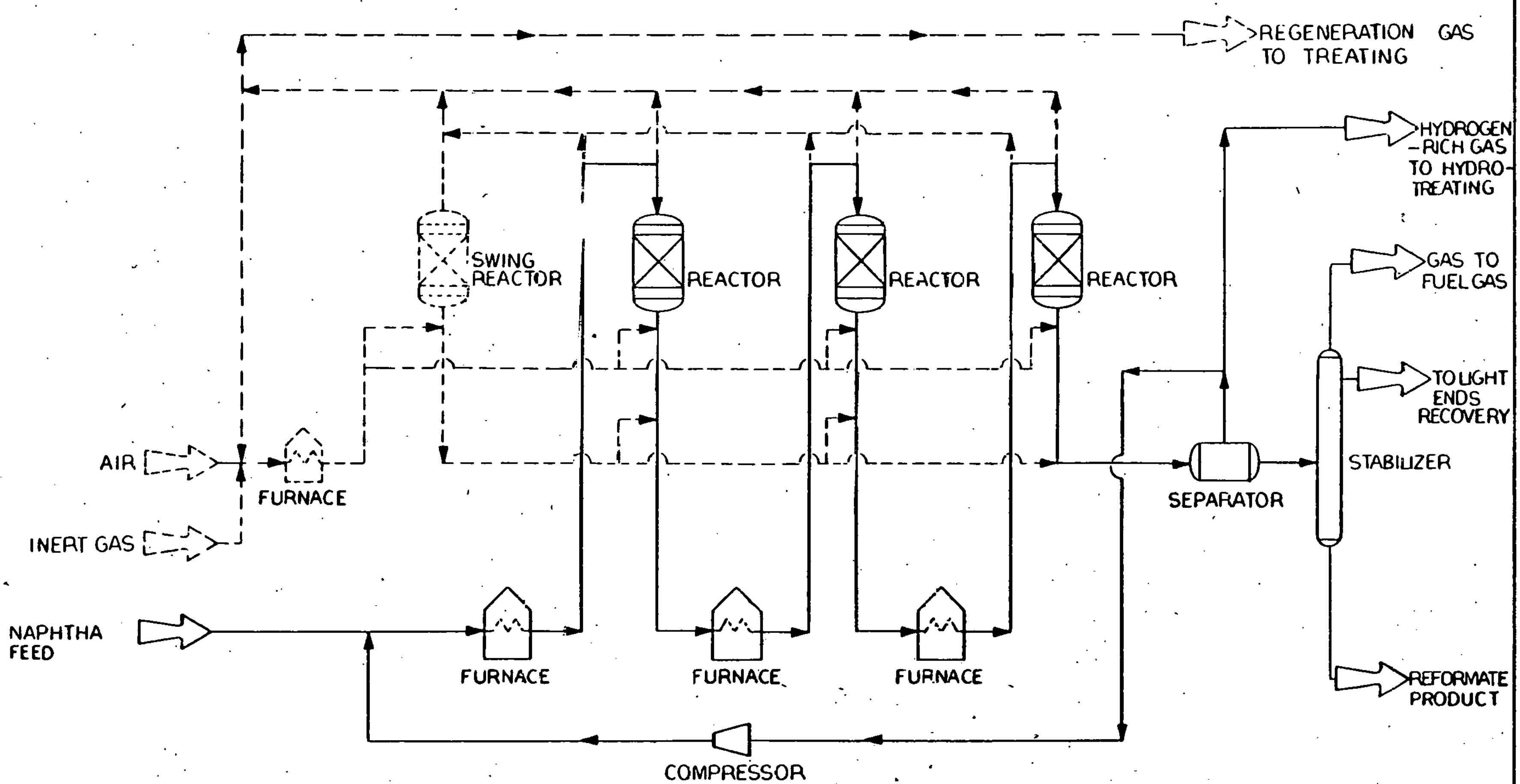
Catalytic reforming is a process used to upgrade low octane heavy naphthas to produce high octane gasoline blending stocks or high yields of aromatic hydrocarbons for petrochemical use (i.e., benzene). The final product will depend upon such variables as reactor temperature and pressure, the catalyst used, and hydrogen recycle rate. Reforming catalysts are readily deactivated (poisoned) by sulfur and the feed must be hydrotreated (desulfurized) prior to being charged to the reforming unit. Typical catalysts are platinum based, but other metals may be used.

Due to the process conditions, reformer catalysts must be regenerated more frequently than hydrotreating catalyst. In some refineries, spent catalyst is replaced rather than being regenerated, but this practice is usually economically prohibitive.

A typical catalytic reforming unit is shown in Figure 8. The naphtha feed is mixed with recycled hydrogen rich gas heated in a furnace and fed to the first reactor. Since the reforming reaction requires heat, (endothermic), the reactor product must be reheated before entering the next reactor. This process is repeated for three reactors. The liquid product then passes to a separator to remove the hydrogen rich gas and then to a stabilizer for final separation of light gases and product. The reformate product then goes to storage for blending into gasoline. The light gases, consisting of mostly propane and butane are sent to light ends recovery.

As shown in Figure 8, a swing reactor is provided to allow for catalyst regeneration without the need to shut the unit down or loss of capacity. As in hydrotreating, during the reforming process, coke is deposited upon the catalyst particles. The regeneration process consists

FIGURE 8
CATALYTIC REFORMING UNIT



of burning off this coke under controlled conditions. The gases (consisting primarily of CO_2) from regeneration are then sent to gas treating for particulate removal before being discharged to the atmosphere.

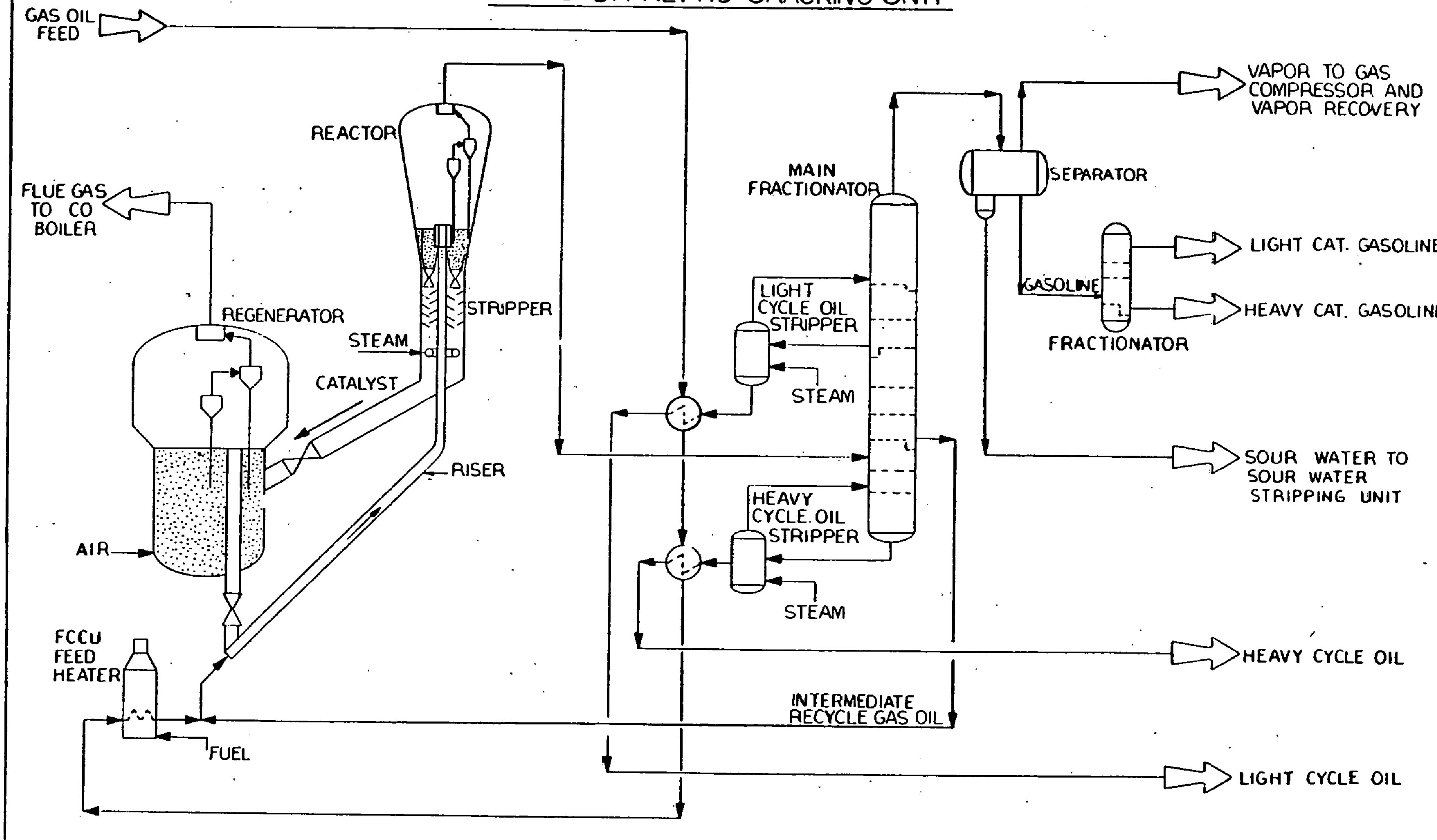
2.5 FLUID CATALYTIC CRACKING UNIT (FCCU)

Fluid catalytic cracking is a low pressure process which uses high temperatures in the presence of a catalyst to break or crack heavier, higher boiling petroleum fractions into lighter more valuable materials. The process catalyst is continuously regenerated and depending upon the sulfur content, the unit feed may be desulfurized prior to processing.

A typical FCCU is shown in Figure 9. While there are numerous FCCU designs currently in use, they employ the similar operating principles. Fresh feed is preheated through heat exchange with the unit product streams. It is further heated to process temperature in a fired heater, mixed with regenerated catalyst and fed through the fresh feed riser to the reactor. The flow and temperature conditions in the riser and reactor are carefully controlled to vaporize the feed and achieve the desired degree of cracking. Since the majority of the cracking occurs in the riser, too short of a residence time in the riser will result in too little cracking; too long a residence time will overcrack the material. In the reactor, the cracking process is completed and the hydrocarbon vapors pass through cyclones to remove entrained catalyst and then to the fractionator. The fractionator separates the cracked product into the various streams. Reactor temperatures are typically 950 to 1400^{o}F and pressures are 10 to 20 psig.

Due to the severity of the cracking operation conditions, catalyst must be continuously regenerated to remove coke which is formed on the catalyst as a by-product of the process. Spent catalyst is discharged from the reactor, steam stripped to remove entrained hydrocarbons, and fed to the regenerator. Air is fed to the regenerator and, due to the high catalyst temperature, the coke is burned off the catalyst and forms a mixture of CO and CO_2. The heat from coke combustion serves to maintain a hot catalyst bed. The regenerator flue gases

FIGURE 9
FLUID CATALYTIC CRACKING UNIT



are passed through cyclones to a CO boiler to burn the carbon monoxide to carbon dioxide and recover heat and generate steam. The regenerated catalyst is then returned to the feed riser. Operating conditions in the regenerator range from 1100 to 1300°F and 10 to 25 psig.

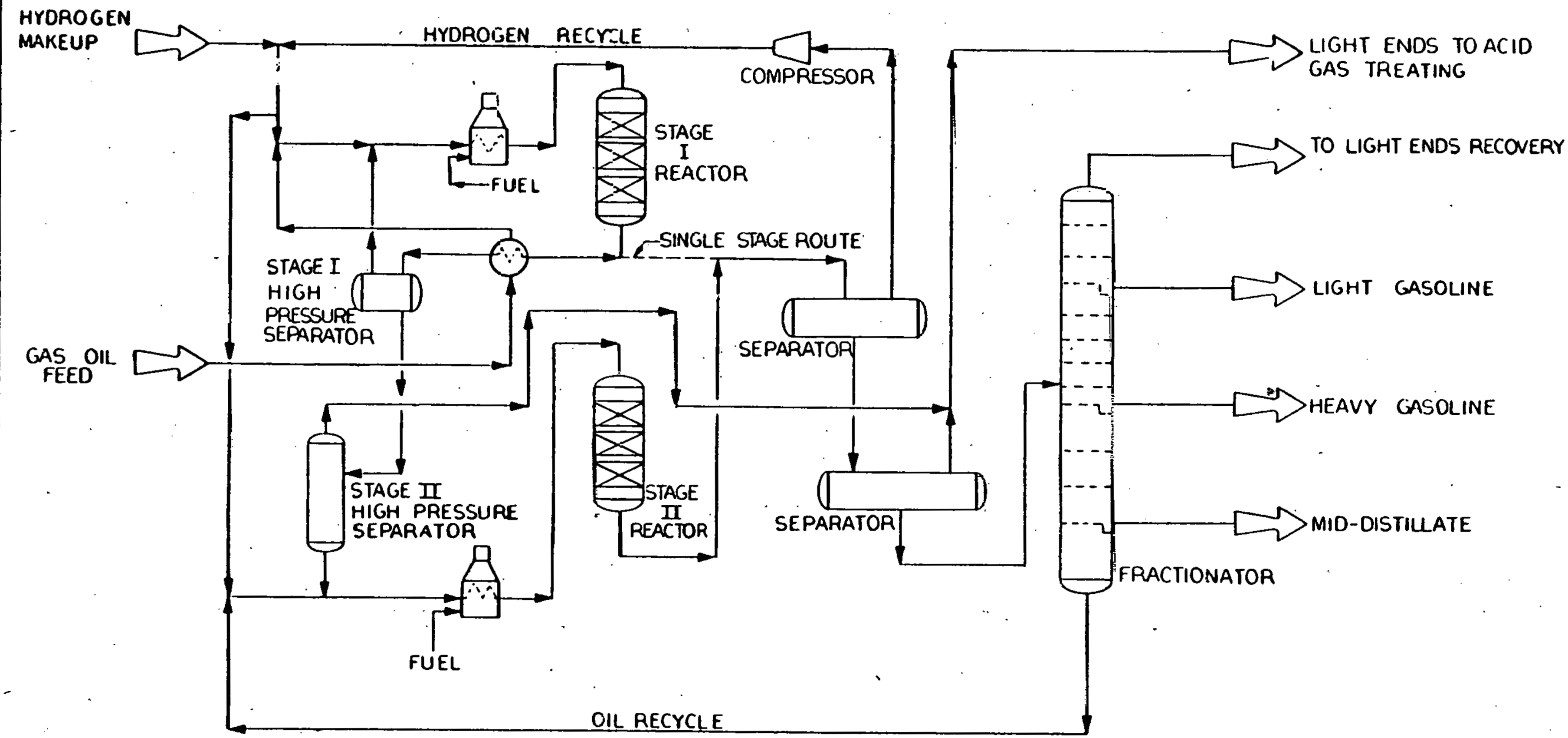
2.6 HYDROCRACKING UNIT

Hydrocracking differs from fluid catalytic cracking in that hydrogen is used in the cracking process and the process pressures are substantially higher (500-4500 psig). Temperatures are, however, somewhat lower (500-550°F) and a different type of catalyst is employed. This process is useful particularly for sour feedstocks in that a high degree of desulfurization is accomplished in the reactor and therefore hydrotreating of sour feeds ahead of the process may not be required. The process produces high quality gasoline and distillates and accepts a wide variety of feedstocks including naphthas, gas oils, and heavy aromatic feedstocks that could cause severe coking if fed to the FCCU.

A typical hydrocracking unit is shown in Figure 10. While Figure 10 shows a two-stage system, single stage processes are also used, primarily with sweet (low sulfur) feedstocks. Feed is mixed with hydrogen, heated, and fed to the first reactor. In this stage, depending upon conditions, some cracking of hydrocarbons occurs, but the principal reactions are the conversion of sulfur to H_2S and the nitrogen to NH_3. The first stage effluent is cooled and fed to the two stage, high pressure separator where the hydrogen-rich gases and light ends are removed. The product from the first reactor is then mixed with recycle fractionator bottoms and additional hydrogen and fed to the second stage reactor where the cracking reactions are completed.

The second stage reactor products then are fed to another two-stage separator where further removal of hydrogen and light ends is accomplished. The liquid product is then fed to the fractionator where the liquid product is separated into the various product streams.

FIGURE 10
HYDROCRACKING UNIT



2.7 DELAYED COKING UNIT

Delayed coking is another type of cracking process which does not employ a catalyst or hydrogen. The process is described as a thermal cracking process in that the cracking is accomplished at high temperature (900-950^{o}F) and low pressures (20 to 60 psig). Feedstocks to coking units typically are heavy bottom products from the vacuum unit and heavy cycle oils from catalytic cracking.

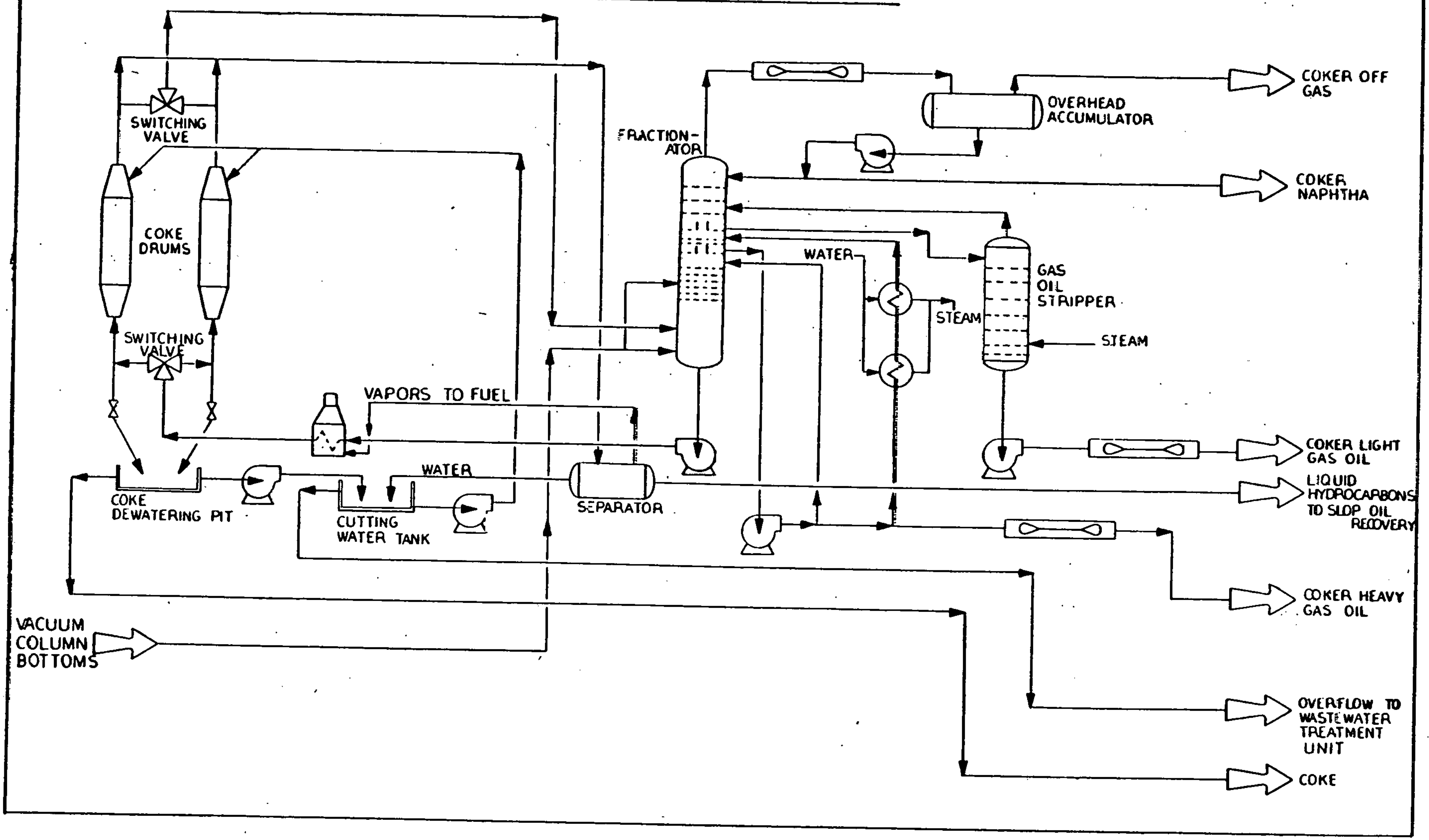
A delayed coking unit is shown in Figure 11. The fresh charge is fed directly to the fractionator where the feed combines with the heavy recycle. The combined feed (fractionator bottoms) then is pumped to the coker furnace where it is heated to coking temperature. This heating produces partial vaporization and mild cracking. The liquid-vapor mixture then enters the coke drum where the liquid undergoes further cracking until it is converted to hydrocarbon vapor and coke. The vapor is further cracked as it passes upward through the coke bed.

The coke drum overhead vapor then enters the fractionator and is separated into coker off gas, coker naphtha, and light and heavy coker gas oils, which are withdrawn as products. The unreacted material is recycled from the bottom of the fractionator and combined with fresh feed for another pass through the system. The unit recovers heat by generating steam in the fractionator side pumparound.

The coking unit typically has at least two coke drums but may have more to accommodate higher feedrates. In the normal operation of a two-drum system, one drum is in service while the other is being decoked.

Decoking is a two-step process in which the coke is first cooled and then removed from the drum. In the cooling step, saturated steam and water are injected into the bottom of the drum. This cools the coke and removes volatile hydrocarbon vapors. The water vapor-hydrocarbon vapor mixture passes to a separator where it is condensed. The separator discharges a vapor stream of non-condensible hydrocarbons which is used as heater fuel, a water stream which is used in the second

FIGURE II
DELAYED COKING UNIT



decoking step, and a liquid hydrocarbon stream which is recovered as slop oil.

When the coke is cool, the drumhead is removed and coke removal (decoking) begins. First, a high pressure water drill is used to bore a pilot hole in the coke bed. Upon completion of the pilot hole, the drill bit is changed to one with specially designed water sprays which loosen (cut) the coke from the drum. The coke and water drop from the drum into a pit where the coke dewaters and the cutting water is recovered for reuse. Excess water is discharged to the wastewater treatment plant. The coke is then removed from the pit by heavy loading equipment either to storage piles or directly onto hauling equipment.

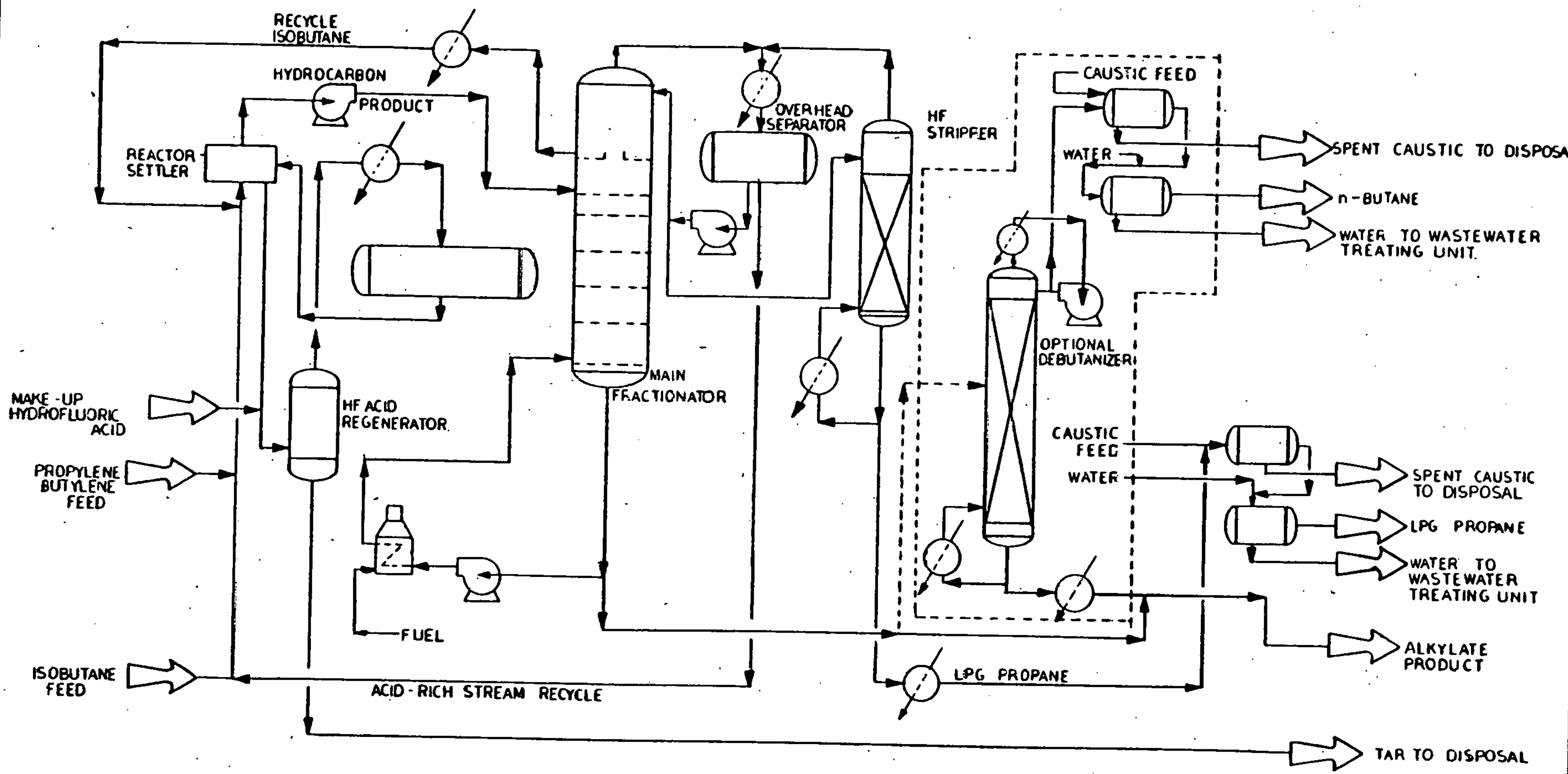
2.8 HYDROFLUORIC ACID (HF) ALKYLATION UNIT

The purpose of the alkylation unit is to convert unsaturated propylene, butylene and isobutane, in the presence of a hydrofluoric acid catalyst,* into a material called alkylate which is blended into gasoline. Propylene and butylene are produced by the fluid catalytic cracking unit and isobutane is recovered from the light ends recovery unit. The alkylate product, when blended into gasoline, will offer a good octane rating which is especially important in the production of unleaded gasoline. Unit operating conditions are typically 100 to 125 psig, and 90 to 120°F, in the reactor, 40 to 100 psig, and 280°F, in the fractionator, and 300 to 390 psig, and 400°F, in the HF stripper. A typical HF alkylation unit is shown in Figure 12.

The unit feed containing principally propylene and butylene is mixed with recycled acid and isobutane and fed to a reactor-settler where alkylation reaction takes place. The hydrocarbon phase is withdrawn to a fractionator where the alkylate product is separated from the unreacted feed, entrained catalyst, and the propane and n-butane that are formed by the reaction. The product alkylate may first be debutanized if necessary, or be pumped directly to storage or gasoline blending.

*Alternative processes may use sulfuric acid rather than HF.

FIGURE 12
HYDROFLUORIC ACID ALKYLATION UNIT



The fractionator overhead product is condensed and collected in an overhead separator where propane-rich and acid-rich fractions are formed. A portion of the propane-rich material is recycled directly to the fractionator, and the remainder is fed to the HF stripper to separate the HF and the liquefied petroleum gas (LPG) product. The LPG is usually sent to a caustic wash to neutralize any acid that may be present and then to storage. The acid-rich fraction from the overhead separator is recycled and mixed with the incoming feed.

The alkylation unit usually also includes an HF regenerator which continuously purifies a small side stream of acid. The tar that is formed in the regenerator may be disposed of by incineration or neutralized with lime and handled as a solid waste.

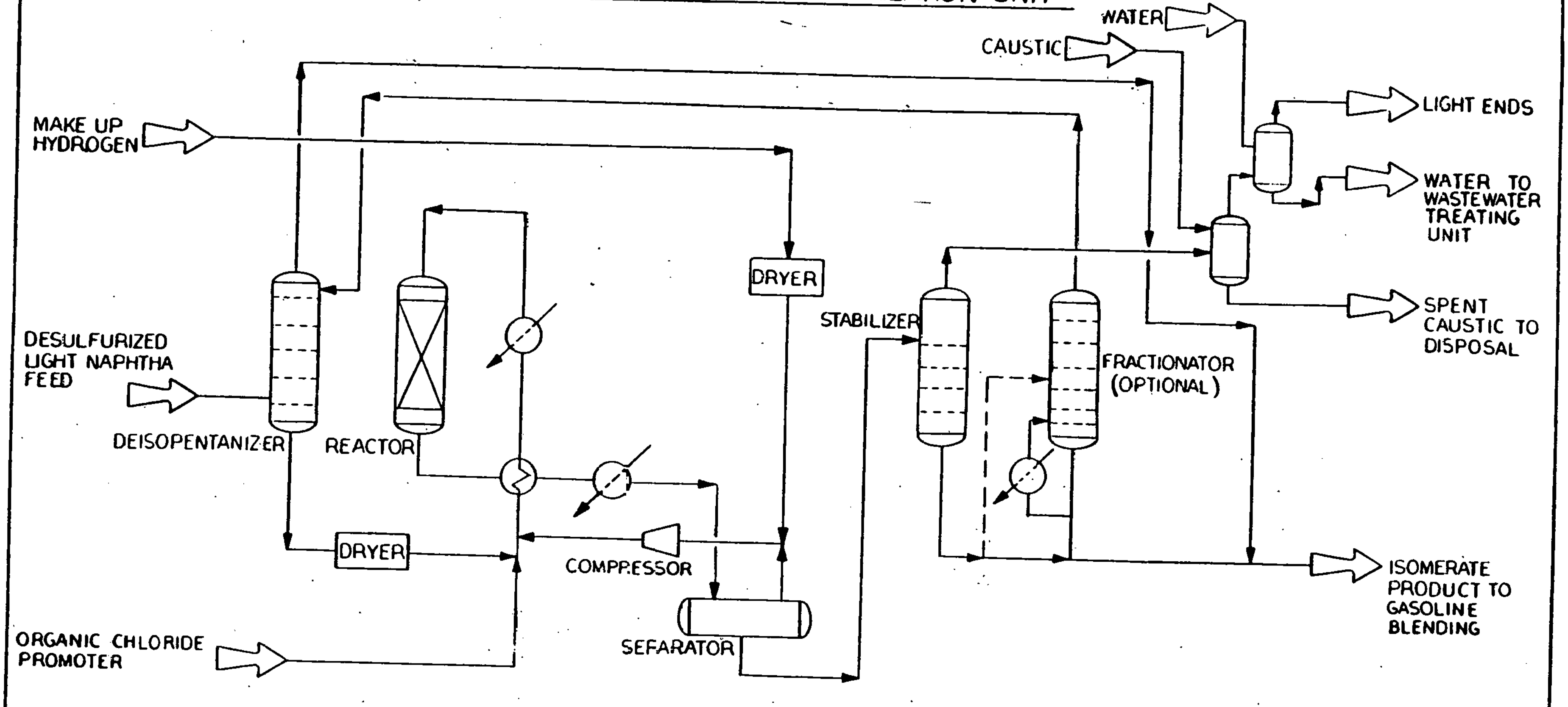
2.9 LIGHT NAPHTHA ISOMERIZATION

The light naphtha isomerization unit is used to convert light naphtha into a motor fuel blending stock called isomerates. The components of the light naphtha fraction are primarily normal pentane and normal hexane. Isomerization is employed to increase the octane rating of pentane and hexane by converting them from the straight chain hydrocarbons form to their branched chain isomers. The process uses a platinum containing catalyst in the presence of hydrogen to affect the isomerization reaction. Operating pressures in the reactor range from 300 to 400 psig and temperatures are typically 250-400^{o}F. Figure 13 shows a typical light naphtha isomerization unit.

In this process, desulfurized pentane-hexane mixtures are fed to the deisopentanizers to remove any isopentane present in the feed. The isopentane is removed overhead and combined directly with the product isomerate. The n-pentane and n-hexane mixture is then dried, mixed with an organic chloride catalyst promoter and hydrogen, and fed to the reactor.* The hydrogen assists in maintaining reactor pressure and helps

*The purpose of the promoter is to increase the activity of the catalyst and increase the rate of reaction.

FIGURE 13
LIGHT NAPHTHA ISOMERIZATION UNIT



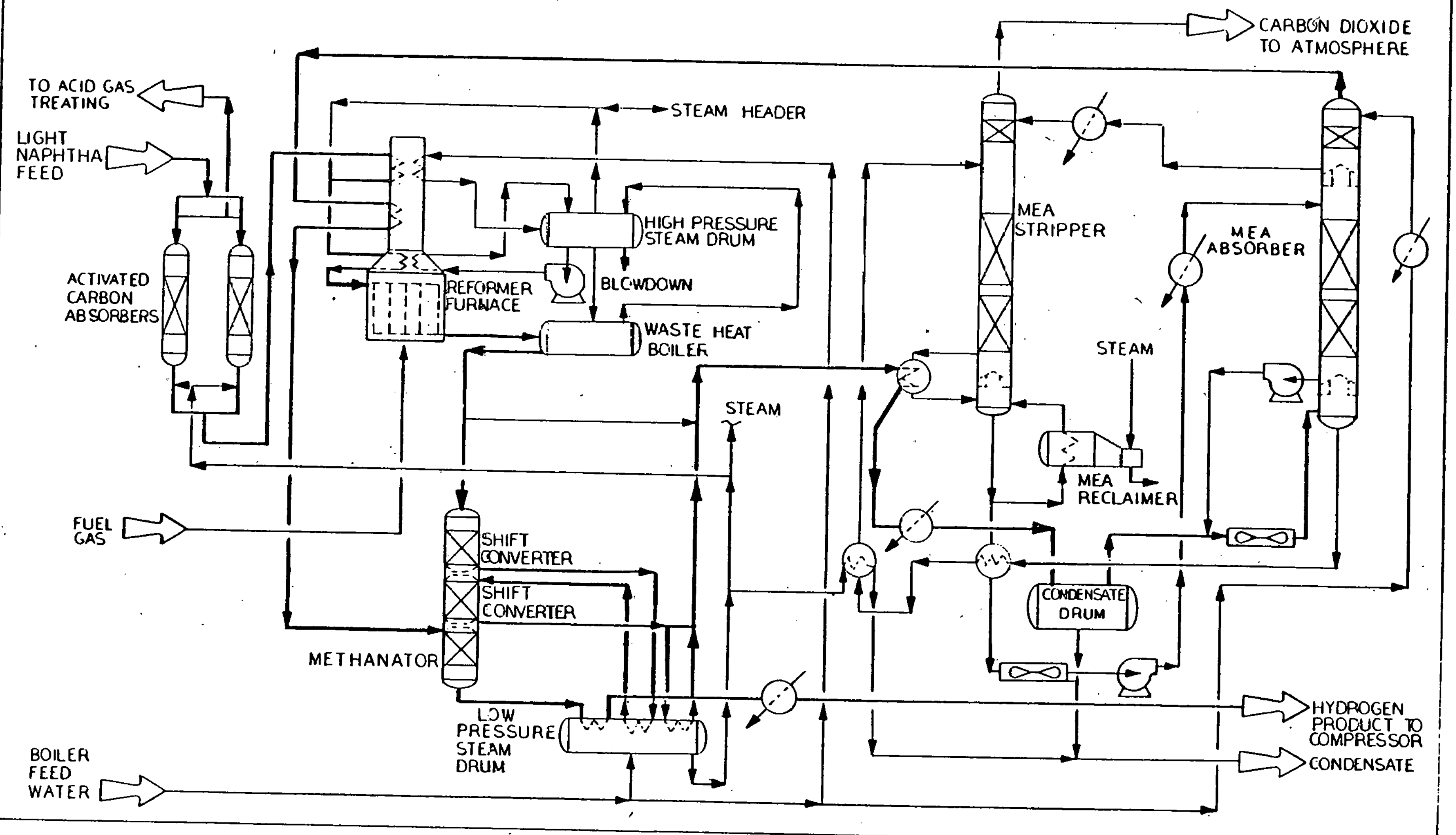
to saturate any olefins or aromatics that may be present. The product is cooled and fed to a separator where excess hydrogen is removed to be recycled. The product is then fed to a stabilizer to remove light ends. The light ends are scrubbed with caustic to remove any hydrochloric acid (HCl) that may have been formed by the reaction. The stabilizer bottom product can then be sent directly into gasoline blending or may be further fractionated to remove unreacted normal pentane and normal hexane for recycle.

2.10 HYDROGEN PRODUCTION UNIT

Hydrogen is used as a reactant in numerous refinery units including hydrotreating, isomerization and hydrocracking. The most widely used method for producing hydrogen is steam reforming of available hydrocarbons such as natural gas, refinery fuel gas, propane, butane, or desulfurized light naphtha. Hydrogen is also produced in the refinery as a by-product in the catalytic reforming process. However, when processing sour crudes, reforming processes will probably not produce sufficient quantities of hydrogen to meet the refinery needs, and, therefore, additional hydrogen production is required.

The sequence of processing steps for hydrogen production by steam reforming is sulfur removal, reforming, shift conversion, carbon dioxide absorption and methanation. In addition, the hydrogen generation process produces sufficient high-pressure and low-pressure by-product steam to satisfy all the needs of the process. A typical flow diagram is shown in Figure 14. The feed to the plant normally contains traces of sulfur which are removed by adsorption on activated carbon. Sulfur removal is required because the process catalyst is poisoned (deactivated) by sulfur. Two carbon beds are used, normally operating in parallel flow. During regeneration, one bed is valved out of the normal flow for regeneration, while the other bed remains onstream. Upon completion of regeneration, the sequence is reversed. Carbon regeneration is accomplished by heating the carbon with steam to remove the absorbed sulfur. The steam is then condensed and sent to the sour water stripper.

FIGURE 14
HYDROGEN PRODUCTION UNIT



The sulfur-free gas is preheated in the upper (convection) section of the reformer furnace and then mixed with high pressure steam. The mixed gas flows downward through catalyst-filled tubes in the lower (radian) where the steam reacts with methane and other hydrocarbons to produce hydrogen, carbon monoxide, and carbon dioxide. The high-temperature effluent gas from the reformer furnace flows through a waste heat boiler which produces high-pressure steam that is mixed with fresh feed. Additional high-pressure steam is generated in the convection section of the furnace. About three-quarters of the total hydrogen product is produced in the forming reaction. The mixture then passes to the two-stage shift conversion reactors. In these reactors the carbon monoxide and water are catalytically reacted to form CO_2 and hydrogen.

The reaction is highly exothermic (heat producing) and the first stage reactor catalyst is a high temperature catalyst. Excess heat is a hinderance to the reaction and is removed from the product between the stages by generating low pressure steam. The second-stage shift converter employs a low temperature catalyst. The lower temperature conditions allow the reaction to go to completion.

The crude hydrogen gas from the shift converter is further cooled and passed through a condensate knockout drum. From here it is sent to the CO_2 absorption system to remove any remaining CO_2. The system shown is a typical CO_2 absorption system using MEA (monoethanol amine) as the absorbent. Many other absorbents are, however, available.

The crude hydrogen is first mixed with a portion of the regenerated MEA, cooled and fed to the center of the tower. The remaining MEA is pumped to the top of the absorption tower. In the tower the remaining carbon dioxide is removed from the gas stream. The hydrogen is then passed from the top of the absorption tower through the convection section of the reforming furnaces to the methanator. The carbon dioxide-rich MEA passes from the absorber to the MEA stripper where the solution is heated and the carbon dioxide is driven off. The stripped MEA is then returned to the absorption system and the carbon dioxide is vented to the atmosphere.

Methanation is a high temperature (600°F) catalytic process which converts any remaining carbon monoxide and carbon dioxide to methane by the reaction with a portion of the hydrogen. Following methanation, the hydrogen is compressed and pressures may range from 200 psig for naphtha hydrotreating to 3500 psig for hydrotreating residuum.

Another catalytic process that is currently being used for hydrogen production is the partial oxidation of residual oils. Feed to these units typically are bottom products from the vacuum tower or heavy coker gas oil, which avoids the necessity of using naphtha or other more valuable hydrocarbons as hydrogen plant feedstock.

In the partial oxidation process, the residual oil is fed to a combustion chamber where it is partially burned in the presence of steam and oxygen. Gases leaving the combustion chamber are composed primarily of hydrogen and carbon monoxide and have a temperature of 2000 to 2800°F. The gases are then quenched with water and steam and fed to a shift converter for further conversion of the CO and steam to hydrogen. The gases are then purified by absorption and the hydrogen product is sent to storage or process units.

2.11 GASOLINE SWEETENING UNIT

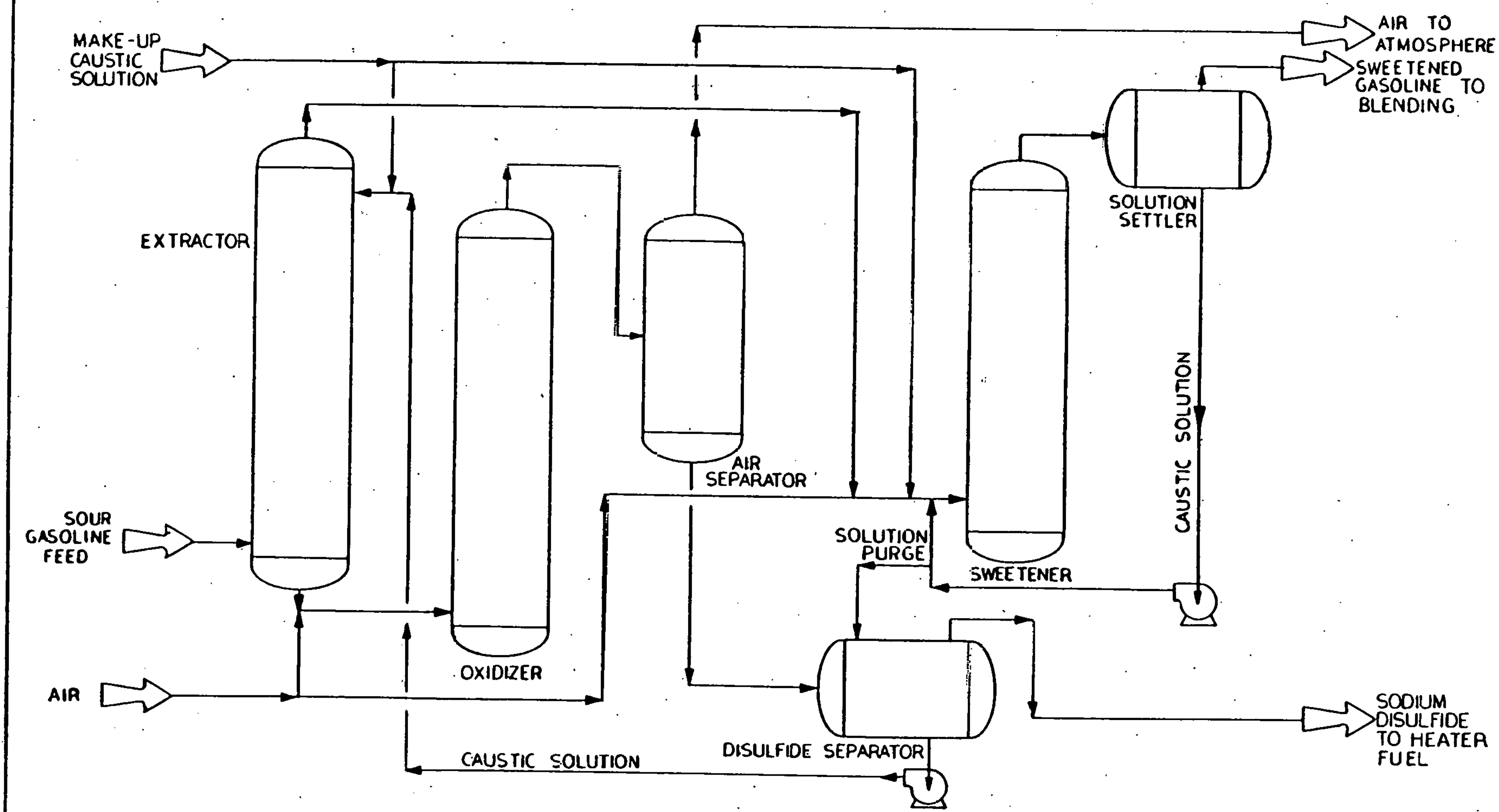
Gasoline is said to be sour if it contains noticeable amounts (>0.1 ppm) of sulfur compounds, particularly the odoriferous mercaptans. A process that removes these compounds or converts them to less objectionable forms is called "sweetening." Gasoline sweetening is usually accomplished by converting the mercaptans to a disulfide. The use of sweetening is dependent primarily on the sulfur content of the crude oil mercaptan, sulfur specifications of the gasoline product, and if the original feedstock had been hydrotreated prior to catalytic cracking.

There is a variety of sweetening processes available including treatment with sulfuric acid or absorption of the mercaptan by molecular sieves. However, the most widely used processes usually employ sodium hydroxide (NaOH) with added catalysts or promoters. Most frequently a caustic solution containing the dissolved catalyst or promoter is employed, but a fixed bed catalyst system may also be used.

Figure 15 shows a typical gasoline-sweetening process that employs a sodium hydroxide solution (caustic) containing a dissolved catalyst. This process is conducted at ambient temperature (90-100°F) and low pressure (5-25 psig). Sour gasoline is fed to the extractor, where it is brought into contact with recycled, regenerated caustic solution. The two streams are immissible and the mercaptans are removed through liquid-liquid extraction. However, only a portion of the mercaptan is removed in the extractor and the partially sweetened gasoline flows from the top of the extractor to the sweetener where it is contacted with additional recycled caustic solution and air. In the sweetener, the remaining mercaptan is oxidized to disulfide. This disulfide remains with the treated gasoline. Caustic solution is separated from the treated gasoline in the solution settler and is recycled to the sweetener.

Caustic solution from the extractor, containing dissolved mercaptan in the form of sodium mercaptan is mixed with air and sent to the oxidizer. In the oxidizer, the mercaptan is oxidized to disulfide and the sodium ion is restored to NaOH. The mixture then flows to the air separator. Excess air is vented from the air separator to the atmosphere and the caustic solution and disulfide flow to the disulfide separator. The insoluble disulfide layer separates and is withdrawn from the system, and the regenerated caustic is recycled to the extractor.

FIGURE 15
GASOLINE SWEETENING UNIT



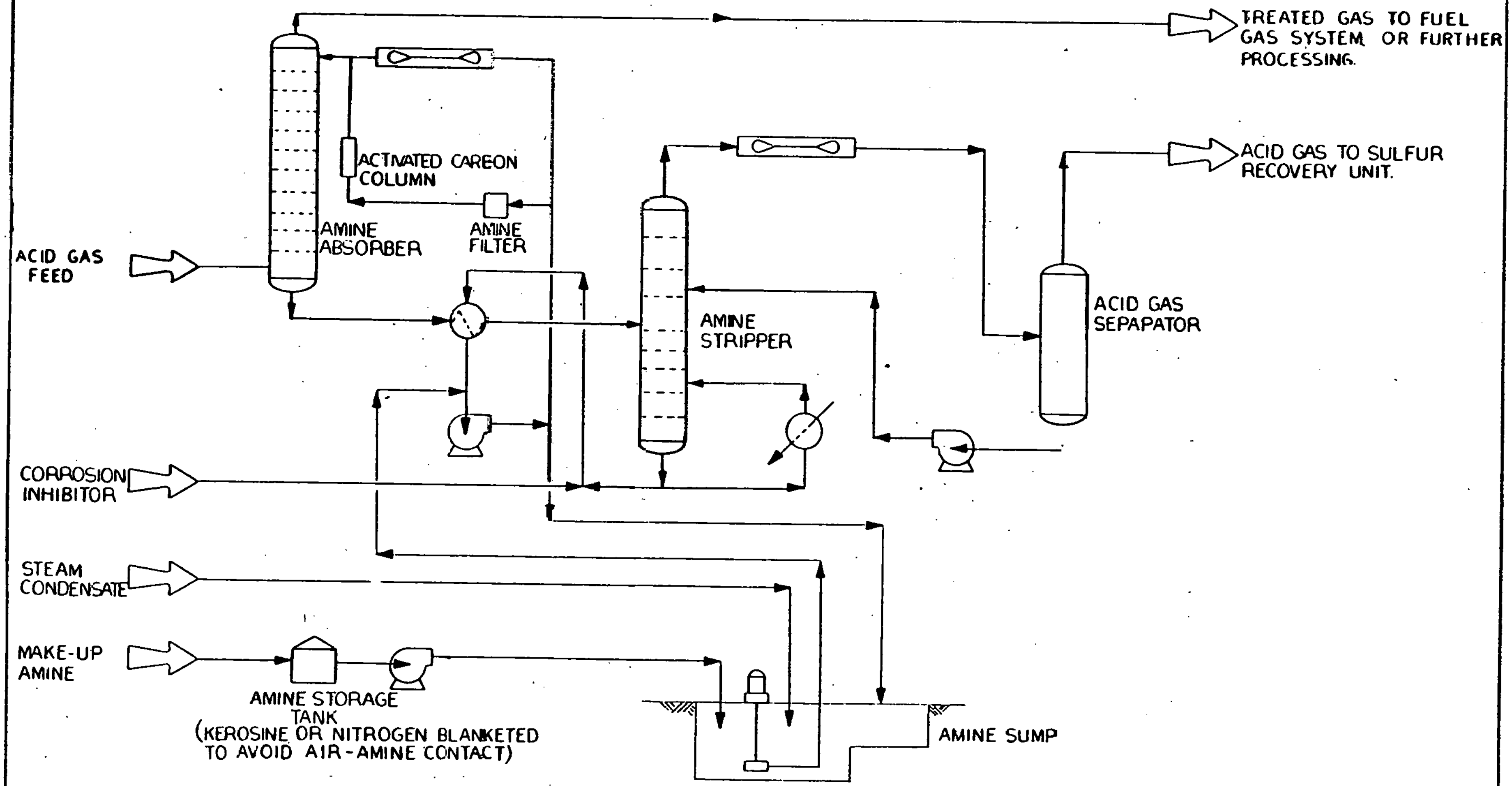
2.12 ACID GAS TREATING UNIT

Hydrogen sulfide (H_2S) and carbon dioxide (CO_2) are termed acid gases, and a gas stream containing these compounds is called sour gas. Sour gas is produced in a number of refinery units including cracking and hydrotreating. Refinery-produced fuel gas can be expected to be sour and it is necessary to treat the gas to remove hydrogen sulfide before it can be used as refinery fuel.

Acid gases are typically removed by absorption in alkaline solution. The alkaline material is chosen so that the chemical bond formed during absorption can be broken by heating to regenerate the solution. Absorbent solutions containing acid gas are termed "rich" and the regenerated solutions are termed "lean." Several acid gas treating processes are available but the differences are primarily in the choice of alkaline absorbent. The most widely used absorbents are monoethanol amine (MEA) and diethanol amine (DEA). The processes are exactly the same except for the absorbent used.

A typical acid gas absorption system is shown in Figure 16. The absorbing medium is a 10 to 20 weight percent solution of amine and water. Sour gas enters the bottom of the column and cool, lean amine enters at the top. Treated gas leaves the top of the absorber and goes to the refinery fuel gas system. Rich amine, containing the absorbed acid gas, is heat exchanged with the lean amine and fed to the top of the stripper. The steam used for stripping the rich amine is generated by boiling the water fraction of a portion of the amine solution in the stripper bottoms reboiler. This eliminates the need for additional stripping steam which would dilute the amine solution. Acid gas and steam leave the top of the column and steam is condensed. The condensate and acid gas are separated in the acid gas separator and the condensate is returned to the stripper as reflux. This practice of condensate recovery reduces the possibility of the amine being concentrated due

FIGURE 16
ACID GAS TREATING UNIT



to water loss. The acid gas goes to the sulfur recovery plant and the hot, lean amine from the stripper reboiler is cooled and returned to the absorber.

In some systems, a portion of the return lean amine is filtered before it enters the absorption tower. The purpose of the filter is to control the amount of particulate matter present in the system. These particulates, typically iron/sulfide, are corrosion products caused by the formation of acids in the system. These acids are formed when the regenerator temperature is too high and amine decomposition occurs. In addition, the presence of oxygen in the system will also cause decomposition of the amine and subsequent acid formation. Therefore, care is taken to avoid contaminating the amine with air. These corrosion products can cause severe foaming and a subsequent carryover of amine from the absorber to the fuel gas system. In addition, the filter may be followed by activated carbon treatment to remove trace organics that may be present, which can also cause absorber foaming and amine carryover.

2.13 SOUR WATER STRIPPING UNIT

Water containing sulfides is termed sour water or sour condensate. Refinery operations produce sour water from processes such as hydrotreating and catalytic cracking and whenever steam is condensed in the presence of gases containing hydrogen sulfide. Sour water usually also contains ammonia, and small amounts of phenol and other hydrocarbons. These contaminants are odorous and may cause wastewater treatment plant upsets and wastewater discharge violations if they were discharged without treatment. Sour water stripping is used by refineries to reduce the level of the contaminants in sour condensate to allow further use of this condensate.

There are many different stripping methods, but most of them involve the downward flow of sour water through a trayed or packed tower while an ascending flow of stripping stream or gas removes the H_2S and NH_3. Operating conditions vary from 1 to 50 psig and 100 to 270^{o}F.

Typical stripping mediums are steam, flue gas or fuel gas, with steam being most commonly used.

Sour water stripping will remove both hydrogen sulfide and ammonia from the water. A typical sour water stripping unit is shown in Figure 17. Sour water is fed to the feed drum which acts as a surge drum for the stripping column. The sour water is then pumped through a preheat exchanger and into the top of the stripper column. Steam is fed into the bottom of the column. Sour gas, containing steam and contaminants, leaves the top of the stripper and is partially condensed. Condensate and sour gas are separated in the surge tank and the condensate is recycled to the stripper. The sour gas is removed to the sulfur recovery unit and the stripper bottoms are fed to the crude oil desalters or discharged directly to the wastewater treatment system. If steam consumption is a concern and maximization of H_2S removal is desired, acid may be added to the sour water feed. This lowers the pH of the feedwater and essentially "fixes" the NH_3 in solution. Since the ammonia is not removed, less steam is required to affect a high degree of H_2S removal.

Sour water stripping will also remove varying amounts of phenols, mercaptans and other contaminants present in the feedwater. The actual amount of these materials removed is dependent upon the unit operating conditions and feedwater characteristics.

2.14 LIGHT ENDS RECOVERY UNIT

The term light ends typically refers to light hydrocarbon gases having four or less carbon atoms. These include methane, ethane, propane, and butane. Also included are C_3 and C_4 olefins and such materials as isobutane. The purpose of the light ends recovery unit is to separate these gases for further use.

A typical light ends recovery unit is shown in Figure 18. The feed to the unit is desulfurized light ends which have been collected from various process units in the refinery. The gases are first liquefied by compression and cooling in order to affect separation by

FIGURE 17

SOUR WATER STRIPPING UNIT

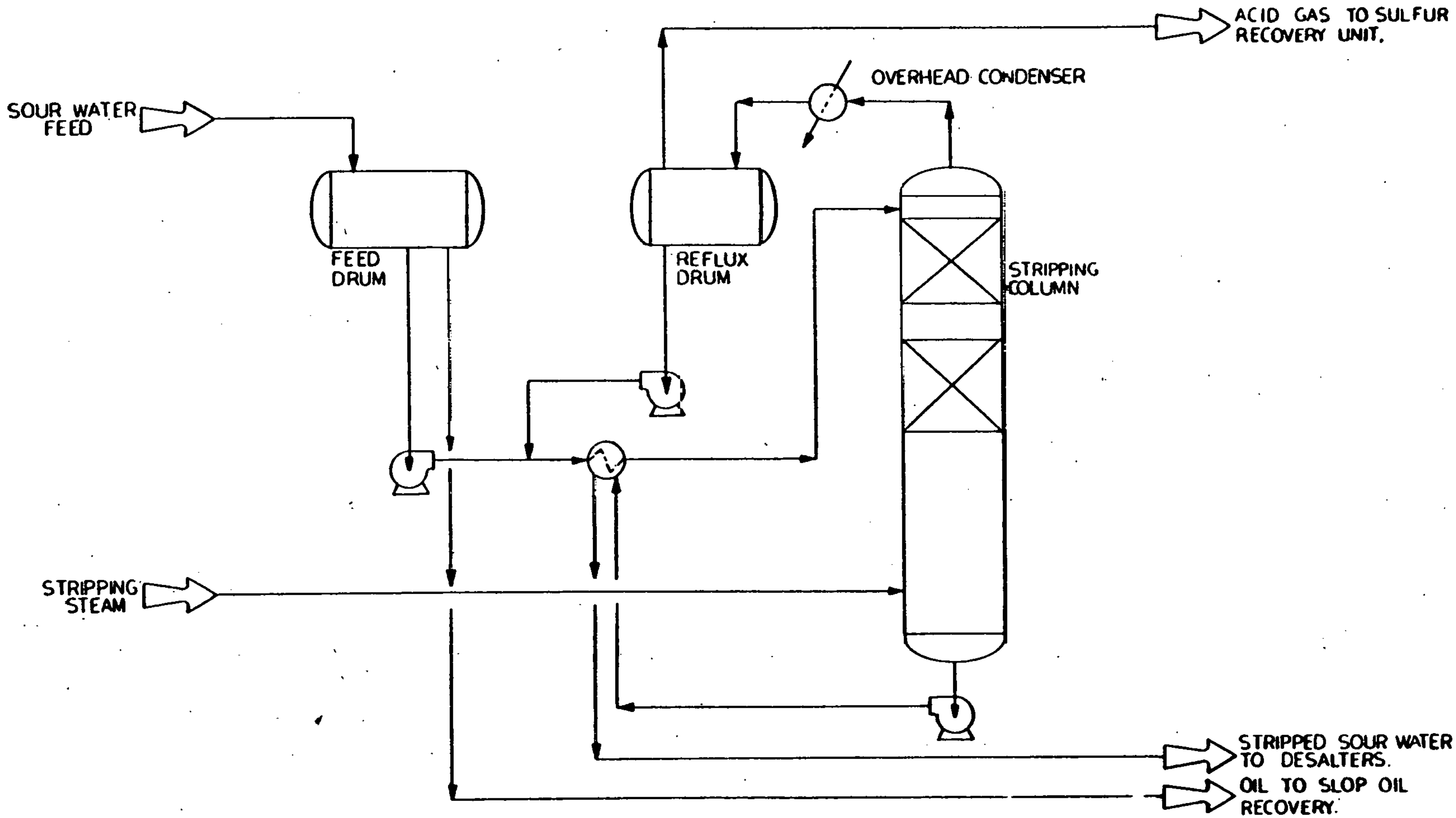
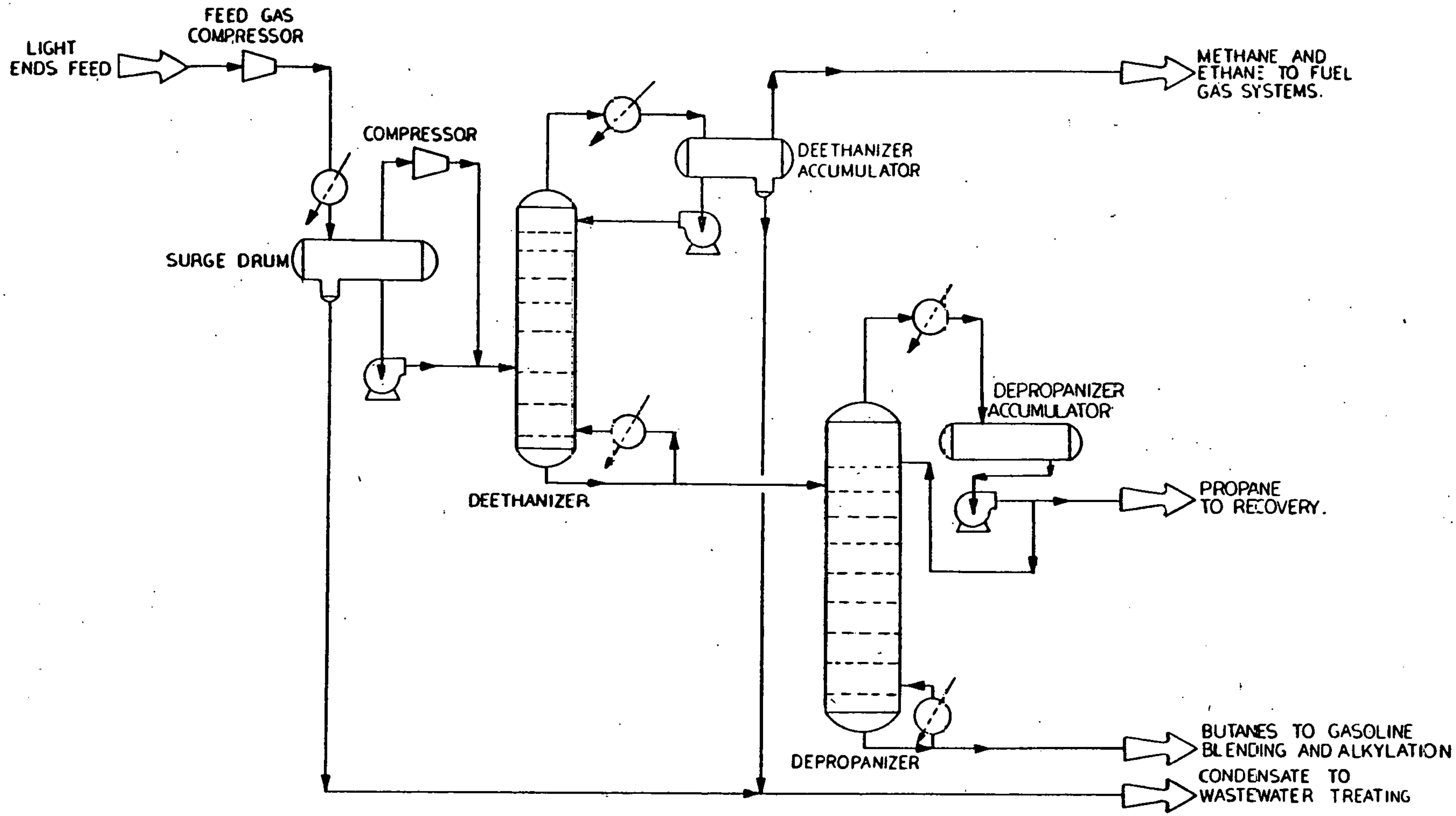


FIGURE 18

LIGHT ENDS RECOVERY UNIT



distillation, and sent to a surge drum to remove any condensed moisture. The mixture is then pumped to the de-ethanizer column where methane and ethane are separated from the mixture and recovered for fuel gas. The de-ethanizer bottoms are then sent to the depropanizer where the C_3 and C_4 compounds are separated. These streams may then be further processed to separate the normal butane and propane from the C_3 and C_4 olefins and isobutanes that may be present. The olefinic and iso-compounds are used as feedstock for the alkylation unit. The n-butane is sent to gasoline blending and the n-propane is recovered as liquefied petroleum gas (LPG).

2.15 SULFUR RECOVERY UNIT

The sulfur recovery unit is used to convert hydrogen sulfide (H_2S) to elemental sulfur. The most widely used sulfur recovery system in refineries is the Claus process which uses both thermal and catalytic conversion reactions. The feed stream contains acid gases (CO_2 and H_2S) from the acid gas recovery plant, along with small amounts of hydrocarbon impurities. The Claus unit is normally designed to convert 95% or more of the H_2S to elemental sulfur. The majority of the remaining sulfur is removed by the tail gas treating unit.

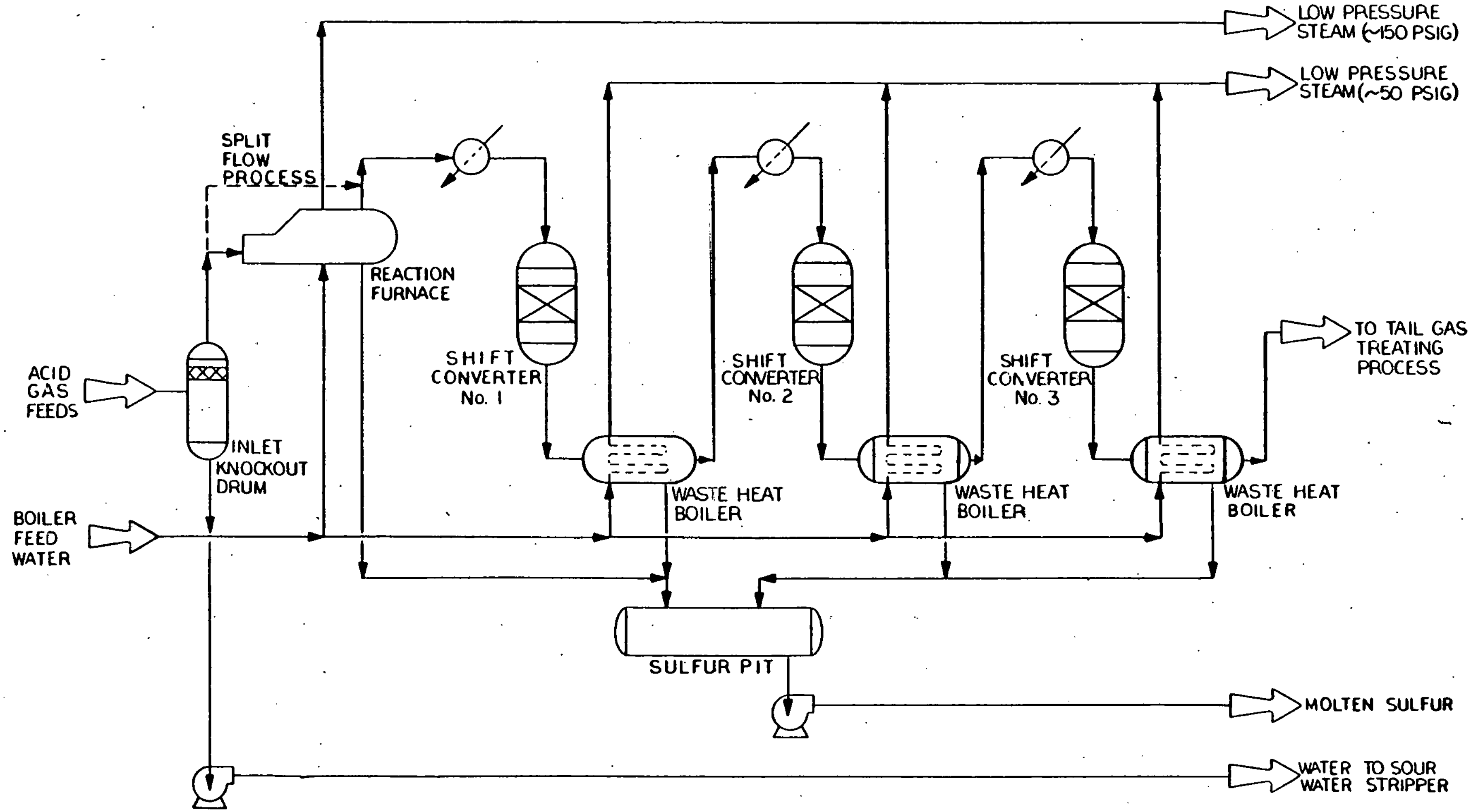
In the Claus process, hydrogen sulfide is converted to elemental sulfur in two steps. In the first step (thermal), H_2S is partially burned with air in a boiler to SO_2. Low pressure steam is generated as a by-product. The H_2S/SO_2 mixture is then reacted over a catalyst to produce sulfur and water by a shift conversion reaction. The shift conversion is carried out usually in three stages with sulfur removal after each stage. The use of the shift conversion reactors allows for more complete sulfur removal and lower operating temperatures would be possible with thermal conversion alone. The design of a sulfur recovery unit depends upon the acid-gas composition. If the concentration of H_2S in the feed is high (more than 40% by volume), a "straight-through" process is used. In the "straight-through" configuration, all of the acid-gas and air are fed to the burner. If the H_2S concentration in the feed is low (less than 40% by volume), a "split-flow" process is used. In the "split-flow" process, a portion of the feed is burned completely to SO_2 and combined with the remainder of the feed to provide the proper H_2S/SO_2 ratio for the shift conversion.

A typical three-stage Claus sulfur recovery unit is shown in Figure 19. The acid-gas stream containing H_2S, CO_2, water and minor amounts of hydrocarbons is fed to an inlet knockout drum to remove any entrained liquid and then fed to the reaction furnace. The furnace consists of two stages. The first is a reaction furnace followed by a waste heat boiler. In the furnace, a portion of the H_2S ($\sim$30%) is burned to SO_2. Due to the high temperatures present, the remaining H_2S and the newly formed SO_2 react to form elemental sulfur. The hot gases and sulfur vapor then pass to the boiler to generate low pressure steam, and thereby condensing the sulfur vapors. The molten sulfur is removed and the remaining H_2S/SO_2 gas mixture is reheated, and fed to the first-stage shift converter. In the converter, H_2S and SO_2 react in the presence of a catalyst to form elemental sulfur. The gases and sulfur vapors are fed to a boiler to generate steam, again condensing the sulfur. The sulfur is removed and the cycle is repeated for two additional stages. The tail gas containing unreacted H_2S and SO_2 is then sent to the tail gas treating unit. The recovered sulfur is then sold as elemental sulfur or used on-site to manufacture sulfuric acid.

2.16 TAIL GAS TREATING UNIT

There are numerous processes available to treat Claus unit tail gas and they are generally divided into reduction and oxidation processes. Both types have been successfully used in refinery applications and the choice of unit will depend upon the tail gas composition and process economics.

FIGURE 19
CLAUS SULFUR RECOVERY UNIT



2.16.1 Reduction Processes

Reduction processes for treating tail gas typically convert all the sulfur compounds in the feed to H_2S. The H_2S is then removed from the gas. The most commonly used reduction processes are the Beavon and SCOT processes.

Beavon Process

The Beavon Process is shown in Figure 20. In this process, the tail gas is first heated to the temperature required for the catalytic reaction to convert all sulfur compounds to hydrogen sulfide by mixing it with a hot stream of gas resulting from partial combustion of hydrocarbon gas in an in-line burner. This gas not only supplies the necessary heat but also sufficient hydrogen to satisfy the requirements of the hydrogenation reactions. After passing through the reactor, the gas is cooled by direct contact with water. The cooled gas, which contains primarily nitrogen, carbon dioxide, and hydrogen sulfide, is then sent to the Stretford column for hydrogen sulfide removal. The water condensed from the gas in the direct contact cooler is sent to the sour water stripper.

The H_2S-rich gas enters the Stretford absorption/reaction column where it is contacted counter-currently with a solution of sodium salts. The treated gas has very low concentrations of sulfur compounds and is released to the atmosphere. Should any unreacted H_2S be present in the tail gas, incineration may be required depending on the H_2S concentration.

The solution then passes to the reaction section of the column where the conversion of H_2S to elemental sulfur takes place. The sulfur solution then is fed to the oxidizer where it is contacted with air. The air serves to separate the sulfur as a froth ($\pm$10%) solids and regenerate the absorption solution. The froth is then fed to a filter or centrifuge for recovery of the solids and the regenerated solution is returned to the absorption column.

SCOT Process

A typical flow diagram for the SCOT Process is shown in Figure 21. Like the Beavon Process, the first step is to catalytically convert all sulfur compounds to H_2S, and the method employed is similar to that used in the Beavon Process.

FIGURE 20
BEAVON TAIL GAS TREATING UNIT

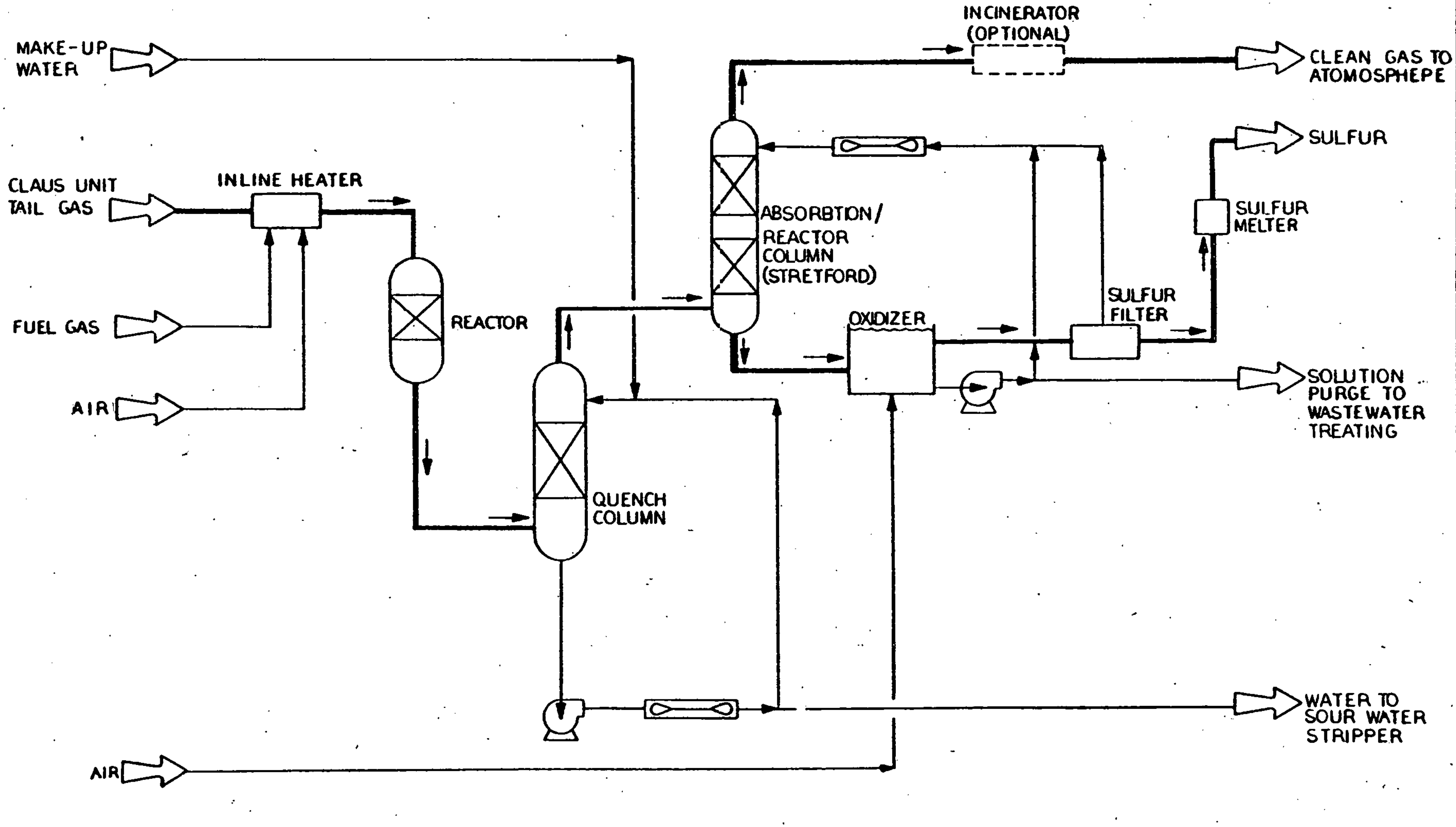
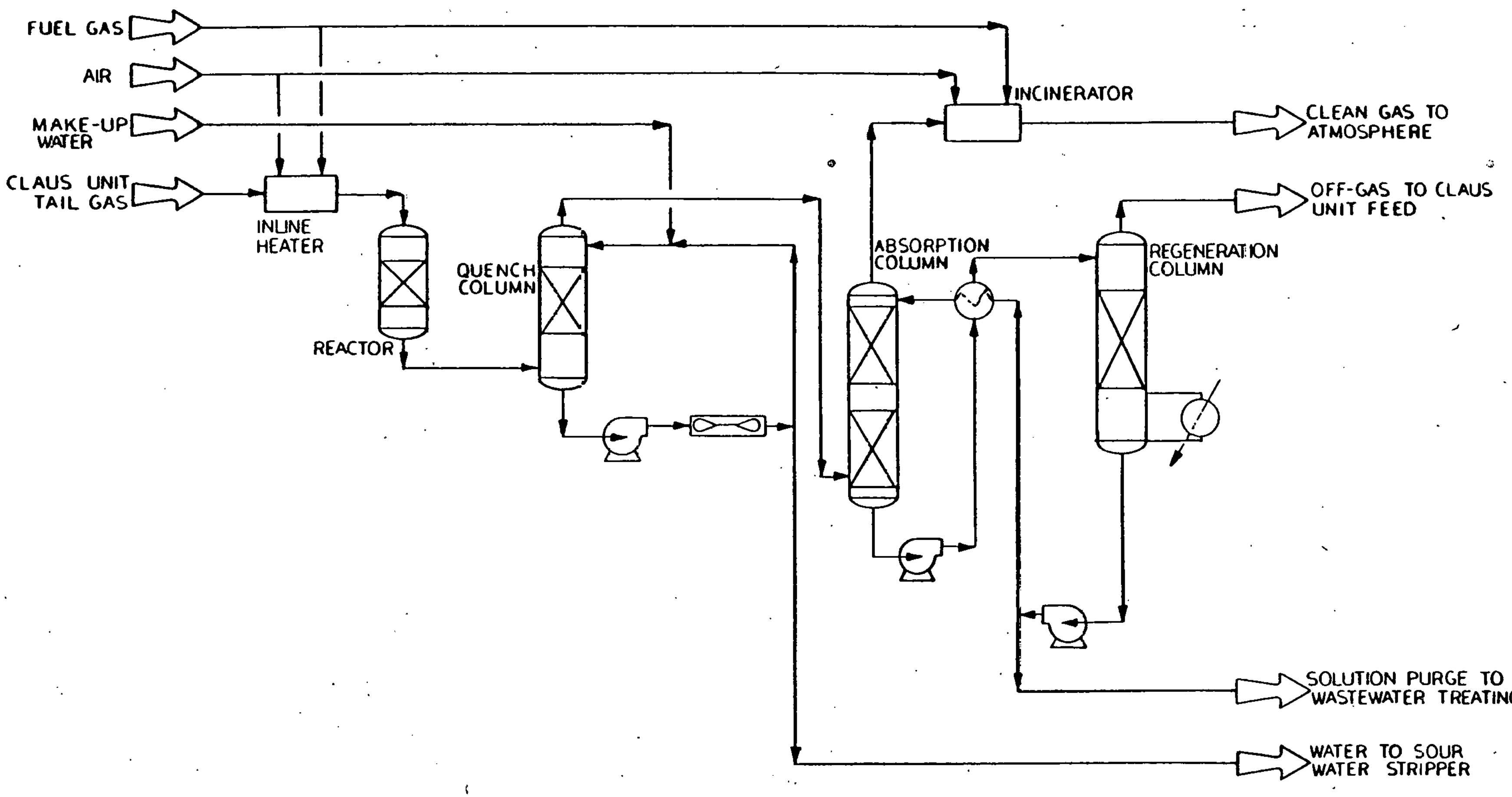


FIGURE 21
SCOT TAIL GAS TREATING UNIT



Following the H_2S conversion, the H_2S-rich gas is quenched with water and fed to the absorber. In the absorber, the H_2S is absorbed from the gas stream by an amine solution (usually di-isopropanol amine). However, unlike the Beavon Process, there is no conversion of the H_2S to elemental sulfur. The treated gas is virtually free of sulfur compounds and is incinerated and released to the atmosphere.

The rich amine solution (containing H_2S) then goes to the regenerator where the H_2S and CO_2 are stripped from the amine in a method similar to that used in the acid gas treating unit.* The gases are returned to the Claus unit and the lean amine is recycled to the absorber.

2.16.2 Oxidation Process

The only oxidation process that is currently being used in refineries to treat Claus plant tail gas is the Wellman-Lord Process.

- Wellman-Lord Process

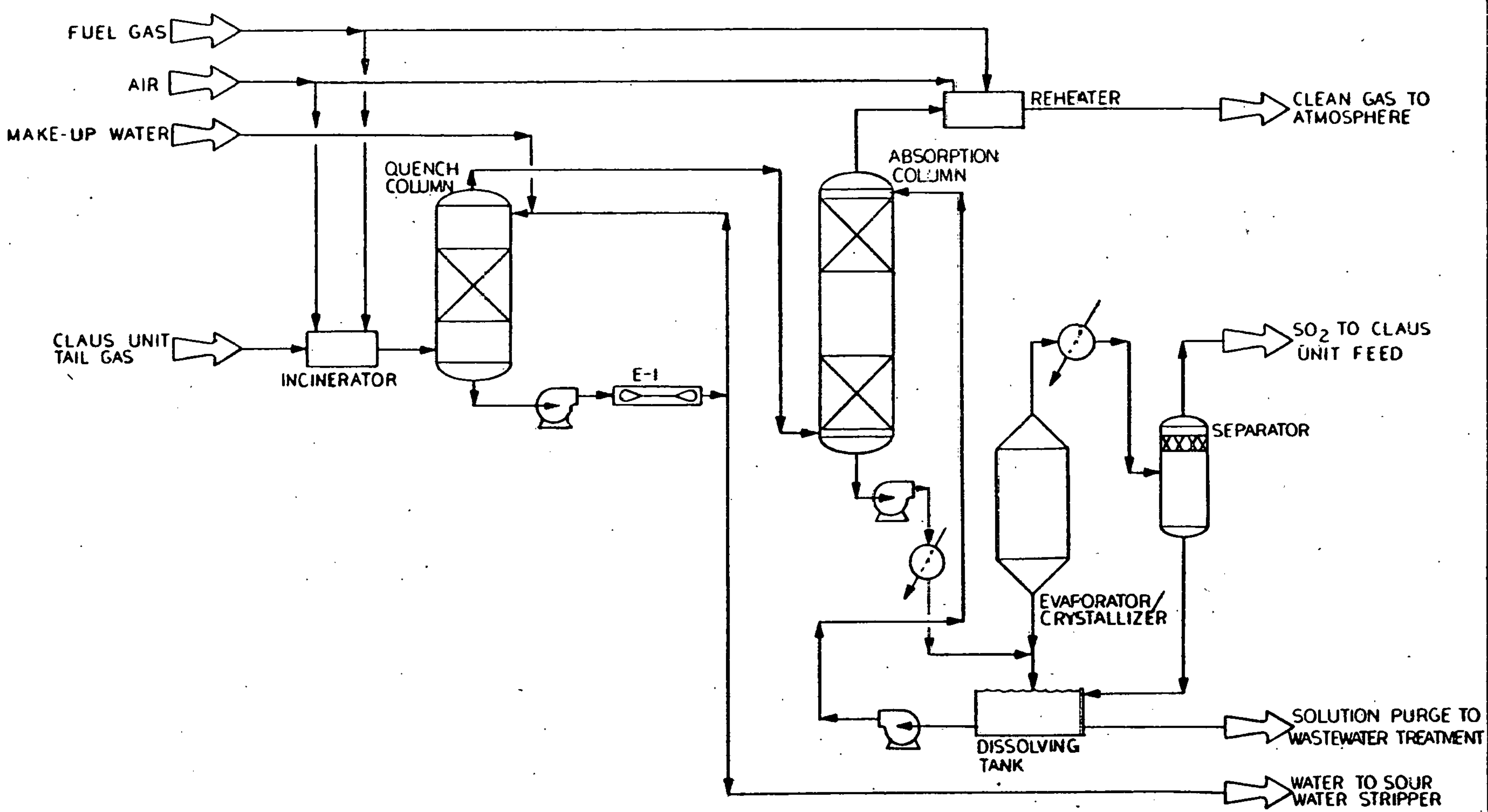
  A typical Wellman-Lord unit is shown in Figure 22. The Claus unit tail gas is first incinerated to convert all sulfur compounds to sulfur dioxide. The hot flue gas is then quenched, cooled, and sent to an absorber. The sulfur dioxide is absorbed from the flue gas with a solution of sodium sulfite. The clean gas contains very low concentrations of sulfur compounds, and can be released to the atmosphere. The solution leaving the bottom of the absorber, now rich in sodium bisulfite with some sodium sulfate, is discharged to a surge tank and then to the evaporator.

  Low pressure steam heats the solution in the evaporator to drive off sulfur dioxide and water vapor. The evaporator overhead is partially condensed to remove the water. The condensate is recycled to a dissolving tank and the sulfur dioxide containing gas is returned to the Claus unit feed.

  The sodium sulfate that is formed in the evaporator when the sulfur dioxide is driven off, precipitates and builds up a dense slurry of crystals. The crystals are redissolved by the overhead condensate and the solution is returned to the absorber.

*See Section 2.12.

FIGURE 22
WELLMAN-LORD TAIL GAS TREATING UNIT



The sodium sulfate which is formed is not regenerable and must be purged from the system. This is generally equivalent to 10 percent of the absorbed sulfur.

2.17 WASTEWATER TREATMENT UNIT

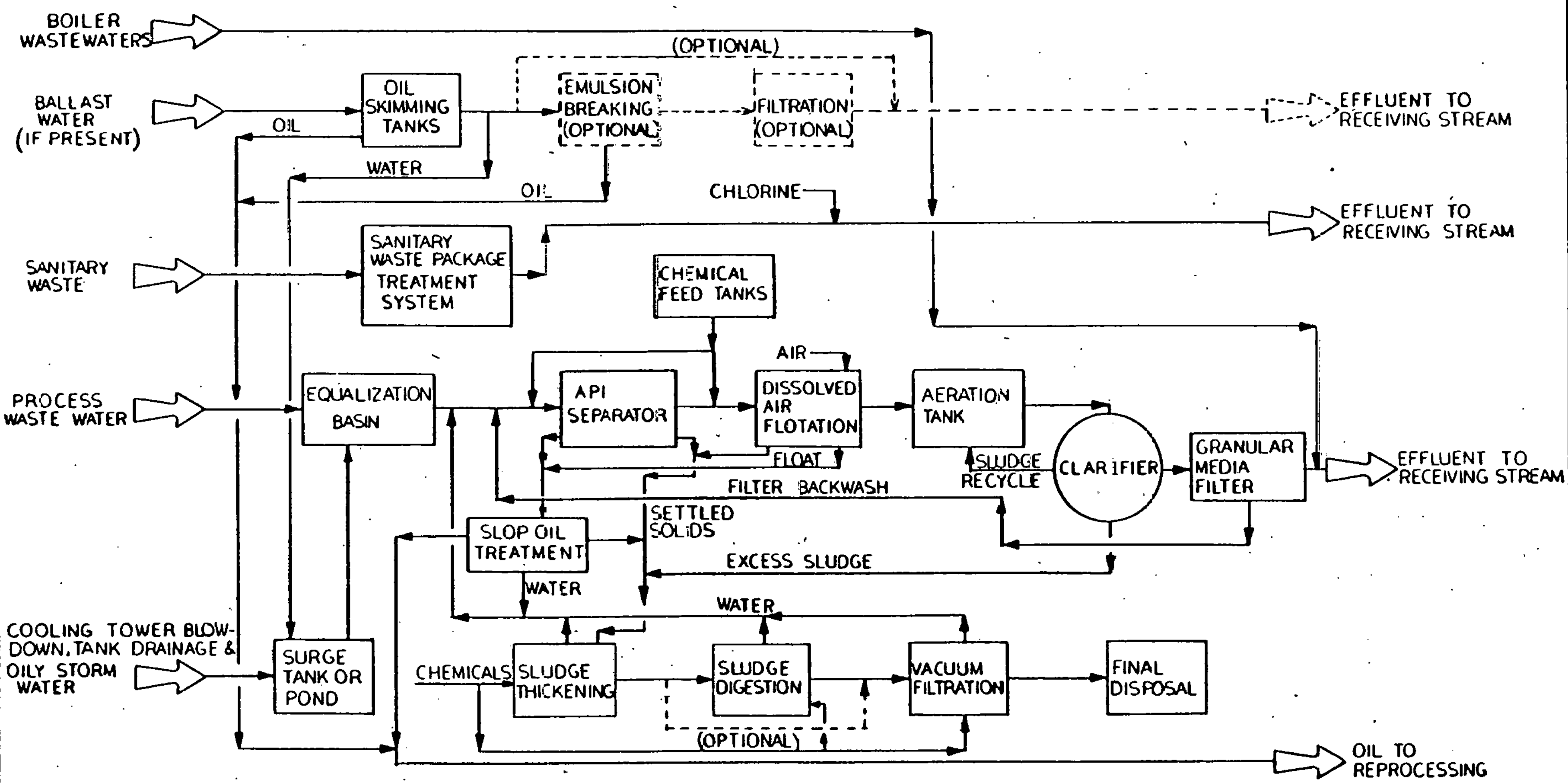
Treatment of refinery wastewater to remove dissolved organic contaminants typically involves both physio-chemical and biological treatment processes, integrated into a single system. This treatment combined with in-plant source control of wastewater produces a high quality effluent suitable for discharge to surface waters.

A typical wastewater treatment unit is shown in Figure 23. This unit represents a system which treats wastewater for discharge to a receiving stream. If the refinery discharges to a publicly owned treatment works (POTW), it may not include the biological treatment section (aeration tanks) and the final clarifiers and filters. Therefore, the actual wastewater treating system will depend upon the decision between stream or municipal discharge.

The wastewater and contaminated storm water enters the equalization basin which serves as a surge tank for the process. From the equalization basin, the flow is pumped to the API separator for the removal of suspended solids and free (floating) oil. The oil collected by the API separator is pumped to the "slop" oil treatment system. This is normally a series of holding tanks in which the oil and water is separated by gravity. The oil is returned to the refinery for reprocessing and the water is returned to the treatment system.

The wastewater stream is then fed to the dissolved air flotation unit (DAF). The purpose of the DAF unit is to remove colloidal solids and oil which cannot be removed from the water by conventional gravity separation. A portion of the DAF effluent is saturated with air and mixed with the unit influent. The air bubbles mix with the oil and solids and cause them to float to the surface of the tank. The float

FIGURE 23
WASTEWATER TREATMENT UNIT



is then skimmed off and returned to the slop oil treating system. Any solids that settle in the DAF tank are handled with the other settled solids. Chemical treatment may be added ahead of the DAF unit which will assist in the removal of emulsified oil.

The flow then passes to the aeration basin where the water is biologically treated to remove contaminants such as dissolved organic constituents (BOD_5) and ammonia. Biological treatment is the removal of the dissolved organic material by microorganisms in an oxygen-rich environment. The flow then enters the final clarifier to remove the biological solids. The clarifier overflow is then passed through granular media filters to remove entrained suspended solids. The filtrate is then discharged to the receiving stream.

Numerous alternatives exist for disposing of the solids generated by the wastewater treating system. The method chosen will depend upon economic and site considerations. In the system shown in Figure 23, a portion of the settled solids (underflow) from the final clarifier is mixed with the settled solids collected in the API separator, DAF unit, and slop oil treatment system, and sent to a gravity sludge thickener. From the thickener, the sludge can be processed by digestion, dewatered by vacuum filtration, and then finally disposed of by land disposal or incineration. Water collected in the sludge processing operations is returned to the head of the waste treatment unit.

The wastewater treating system shown in Figure 23 represents the treatment technology required to meet the Best Practical Control Technology (BPCT) refinery wastewater discharge regulations.* To meet the 1984 regulations, additional treatment such as the application of powdered activated carbon in the aeration basin for the removal of residual dissolved organic materials and processes such as reverse osmosis to remove dissolved inorganic solids from the effluent may be required. These processes can be added to existing treatment facilities. The wastewater treatment system for new refineries in addition to the

*Reference 16

activated carbon and dissolved solids removal systems may also include segregated treatment of specific waste streams and two-stage biological treatment as part of the initial plant design.

Boiler blowdown, sanitary wastes and ballast water may be treated separately from the main process wastes. Sanitary wastes are collected separately and treated in a package biological treatment plant designed specifically to treat domestic waste. This practice avoids the costly requirement of chlorinating the entire refinery discharge due to the presence of sanitary wastes as well as the possible formation of chlorinated hydrocarbons in the receiving water. Boiler blowdown and other boiler wastewaters usually do not require treatment and can be discharged directly.

In the case of coastal refineries or refineries served by tanker, ballast water from tankers must also be collected and treated, primarily for oil removal. The ballast water is first pumped to holding tanks where free oil and suspended solids are allowed to separate by gravity. The tanks are typically equipped with skimmers to remove the separated oil which is sent to the refinery for processing. The water can then be discharged directly with the plant effluent, sent to the wastewater treatment plant for further treatment, or can be pumped to a second series of tanks for removal of emulsified oil before being discharged. The actual ballast water treatment system employed will depend upon the characteristics of the waste.

2.18 REFINERY OFF-SITES

Refinery off-sites are a general category of equipment, systems and facilities that are used in support of the refining unit operations. In addition to the major off-sites discussed in this section, off-sites include such facilities as garages, machine shops, storehouses and necessary offices.

2.18.1 Tankage

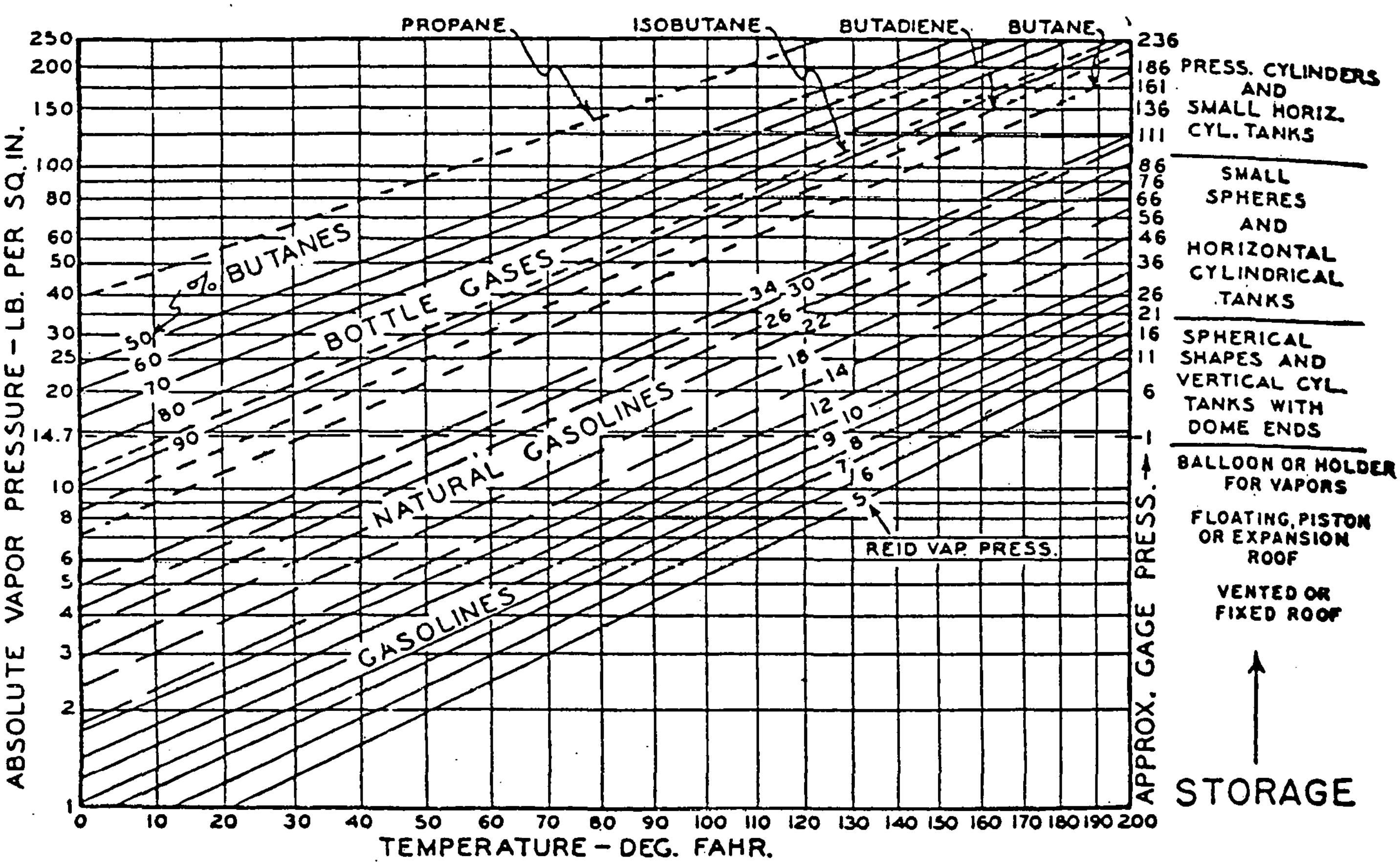
Tankage in a refinery is provided for the storage of crude oil, intermediate and finished products and gases in both the liquefied and gaseous forms. Refinery tankage requirements will vary depending upon such factors as the number of products the refinery produces and the volume of crude oil inventory that is maintained. Consideration must also be given to store intermediate products when units are brought down for maintenance. While some tankage is located near process units for storage, chemical handling or safety purposes, the largest tanks are located in separate areas commonly known as tank farms or tank fields. Each tank is typically surrounded by earthen dikes which will confine any liquid material that may leak from the tanks. The dikes are primarily for fire control. In addition, the tankage system has a designated pumping and piping system which allows free movement of material between various tanks, to and from process units, as well as in and out of the refinery.

Many tank designs are available for the storage of liquid products and gases. The type of tank required for storage of a given material depends primarily upon the vapor pressure of the material and the storage temperature. Figure 24 shows the relationship between vapor pressure, temperature, and the type of storage vessel used. In general, liquid products, such as gasoline and other materials with low vapor pressure, are stored in flat bottom tanks with either fixed or floating roofs. A number of these tanks may also be equipped with internal steam coils and mixers for the storage of highly viscous oils. Gases and other materials with high vapor pressures are commonly stored in spheres and cylinders.

The fixed and floating roof tanks which are used to store materials such as crude oil and gasoline typically are the largest storage vessels in the refinery. Individual tanks have capacities that may range from 5000 to more than 200,000 barrels (210,000-8,400,000 gallons). On a fixed roof tank, the roof is rigidly fixed in place,

FIGURE 24

TYPES OF STORAGE TANKS USED
FOR VARIOUS HYDROCARBON MATERIALS

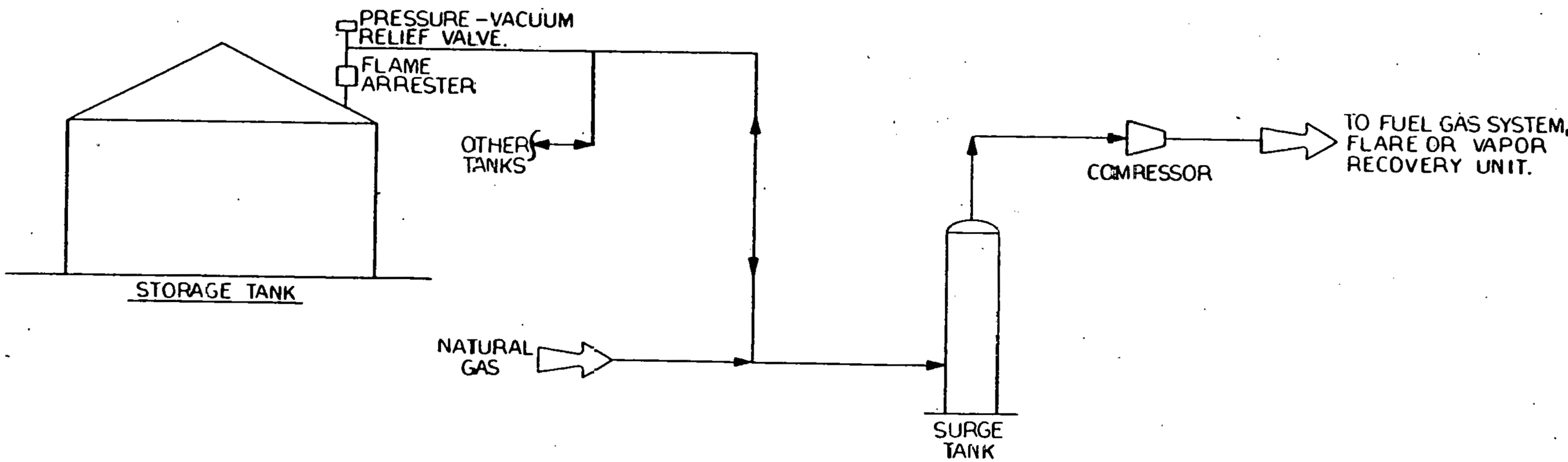


and the vapor space above the liquid changes with the tank liquid level. Considerable amounts of hydrocarbon vapor can be generated from these tanks when tank volumes are low. In some cases, a moveable inner liner floats on the liquid surface to minimize this vapor space, even under low level conditions. On a floating roof tank, the entire roof floats on the surface of the liquid, and thus rises and falls with the liquid level. This maintains a minimum vapor space above the liquid and thus minimizes the amount of hydrocarbon vapors which are lost to the atmosphere.

The portion of the refinery tankage system which handles volatile petroleum fractions is connected to a vapor recovery or relief system. This system collects hydrocarbon vapors and protects the tanks from over-pressurization. The major vapor losses occur during filling of the tanks. Spheres and other vessels handling higher vapor pressure materials and liquefied petroleum gases typically are connected directly to the fuel gas or the refinery flare system. Tanks handling lower vapor pressure materials typically are connected to a recovery system which will collect and compress the vapors so they can be returned to the fuel gas system or to a central vapor recovery system.

A tankage vapor recovery system is shown in Figure 25. Fixed roof tanks are interconnected with a vapor piping manifold and are typically equipped with combination pressure-vacuum relief valves, which will protect the tanks from both over-pressurizing and depressurizing (vacuum). The proper tank pressure is maintained by admitting natural gas to the manifold when the pressure falls, and by removing vapor by means of the compressor when pressure rises. Normally, on a large system the compressor may run continuously in order to maintain a low pressure in the surge tank. Recovered vapors are discharged to the fuel gas system, flared, or most typically combined with vapors from other sources such as loading facilities and sent to a central vapor recovery system.

FIGURE 25
TYPICAL TANKAGE VAPOR RECOVERY SYSTEM



Types of vapor recovery systems include scrubbers and packed towers which employ, for example, hydrocarbon (i.e., gasoline) absorbents to separate the vapors from the air. The recovered hydrocarbon vapors are then removed from the absorbent, compressed and sent to the fuel gas system or back to the crude oil storage tanks. The absorbent is then returned to the vapor recovery system.

2.18.2 Steam Generation System

Steam is used as heating medium in various refinery operations and as a process fluid in others such as hydrogen production, steam stripping, and in turbines to drive pumps and compressors.

Refinery steam systems typically consist of closed loop and open systems. In the closed loop system, the steam generated yields its heat to process streams in heat exchangers by condensation. The condensate is then returned to the boiler. The open system is the steam used for stripping in fractionating towers, etc., and the steam lost must be made up as feedwater to the boiler. Boiler fuel may be either fuel oil or fuel gas, and major refinery boilers produce at least 750°F, 600 psig steam. This pressure is then reduced by turbines or use of the high pressure steam in refinery processes to provide the lower pressure (250 psig, etc.) steam requirements. Low pressure exhaust steam condensate is collected and returned to the boiler house.

Figure 26 shows a typical steam generation unit. Fresh makeup water is first treated by softening and deionization to achieve the proper boiler feedwater quality. The feedwater is preheated with the boiler blowdown and pumped to the deaerator to remove dissolved oxygen by steam stripping. The treated makeup water is then mixed with the recycle condensate. The water is pumped from the deaerator to the boiler for conversion into steam.

As part of normal boiler operation, a small water stream, or blowdown, is discharged from the boiler to control the concentration of dissolved salts and other impurities that can corrode or foul the boiler internals. Blowdown can be continuous or intermittent, and its heat is

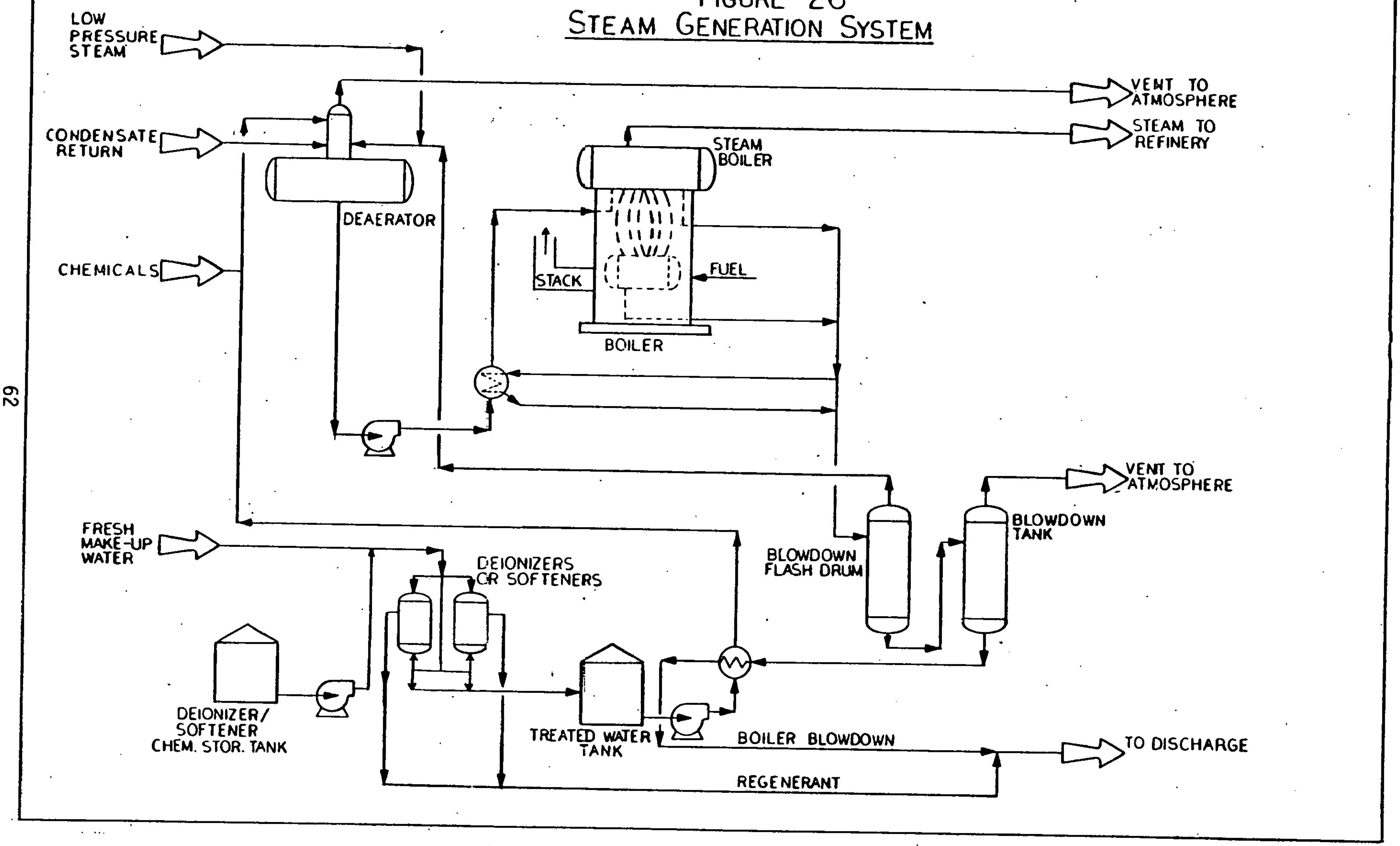


FIGURE 26
STEAM GENERATION SYSTEM

recovered by exchange with the boiler feedwater. To avoid undue heat, loss, boilers are operated to minimize blowdown requirements and typically, blowdown volumes are less than 5% of the boiler feedwater makeup rate.

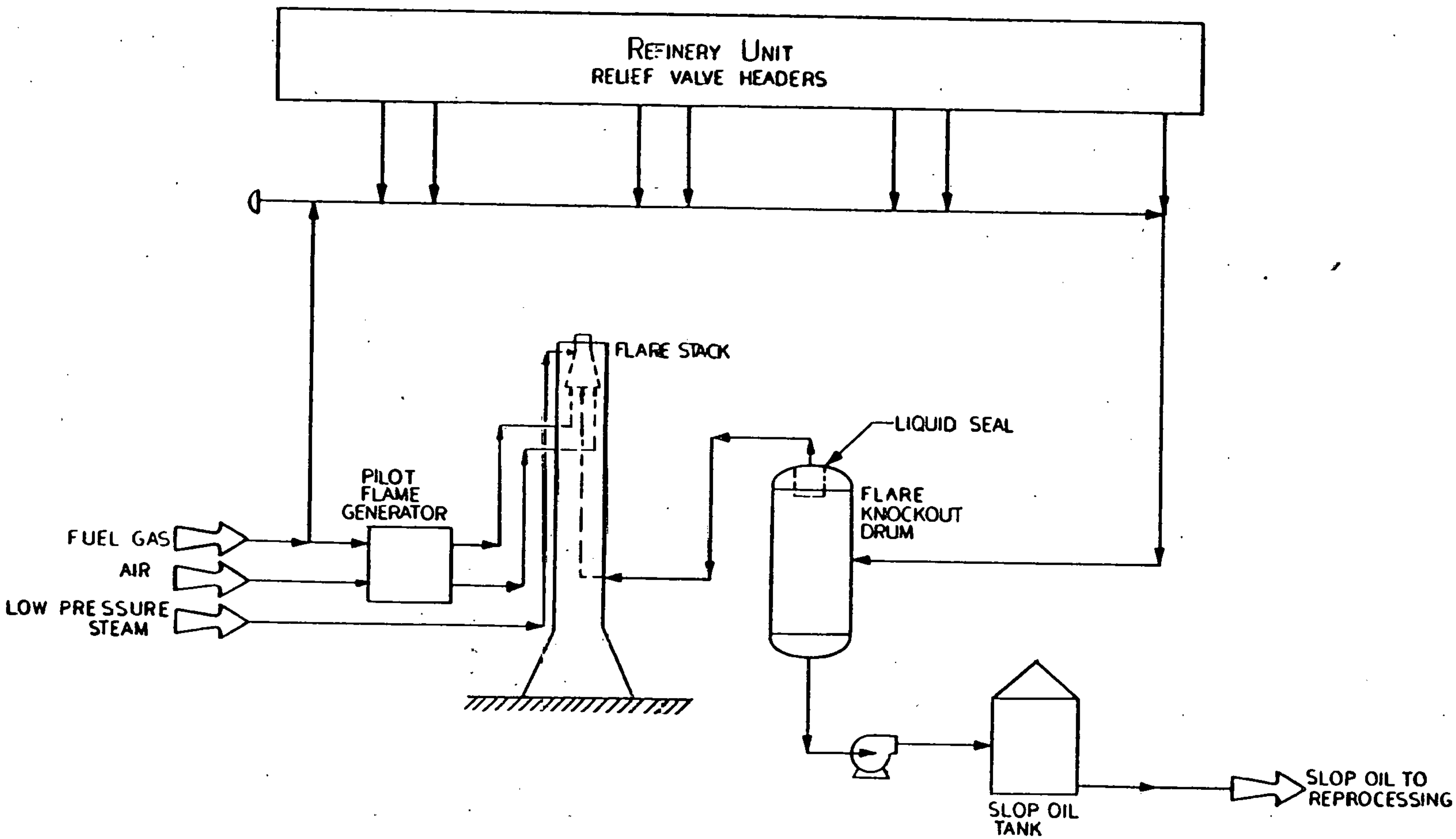
In addition to the main steam generation unit, some process units such as the catalytic cracker and the hydrogen plant will produce steam for process use. The boilers located on these units are operated essentially in the same manner as the main plant boiler except the fuels used are process flue gases rather than fuel oil or fuel gas.

2.18.3 Flare and Blowdown System

The heart of the refinery safety are the flares. During processing unit upsets and plant emergency conditions, such as power failures, higher than normal pressures may be generated in certain process equipment. To protect this equipment from damage, and for operator safety, pressure relief devices are installed and set to open at a pressure below the design pressure of the equipment. Hydrocarbon vapors released when these valves open are collected and burned by a flare. Figure 27 shows a typical flare system.

Under normal operating conditions, when no systems are relieving to the flare header, a small purge of fuel gas is used to keep a positive pressure in the line and the flare flame burning. Steam is injected into the burning hydrocarbons to produce a smokeless flame. During emergency conditions, the relieved process fluids flow through the flare header to the knockout drum, where any entrained liquid is separated. The vapors from this drum flow through a liquid seal to the flare and are burned. The liquid is pumped to the "slop" oil system for reprocessing. Process units such as catalytic cracking units or sulfur recovery units may have individual flares while other units may be manifolded into a single flare stack. This is dependent upon the operating conditions of the individual units and the overall plant layout.

FIGURE 27
REFINERY FLARE SYSTEM

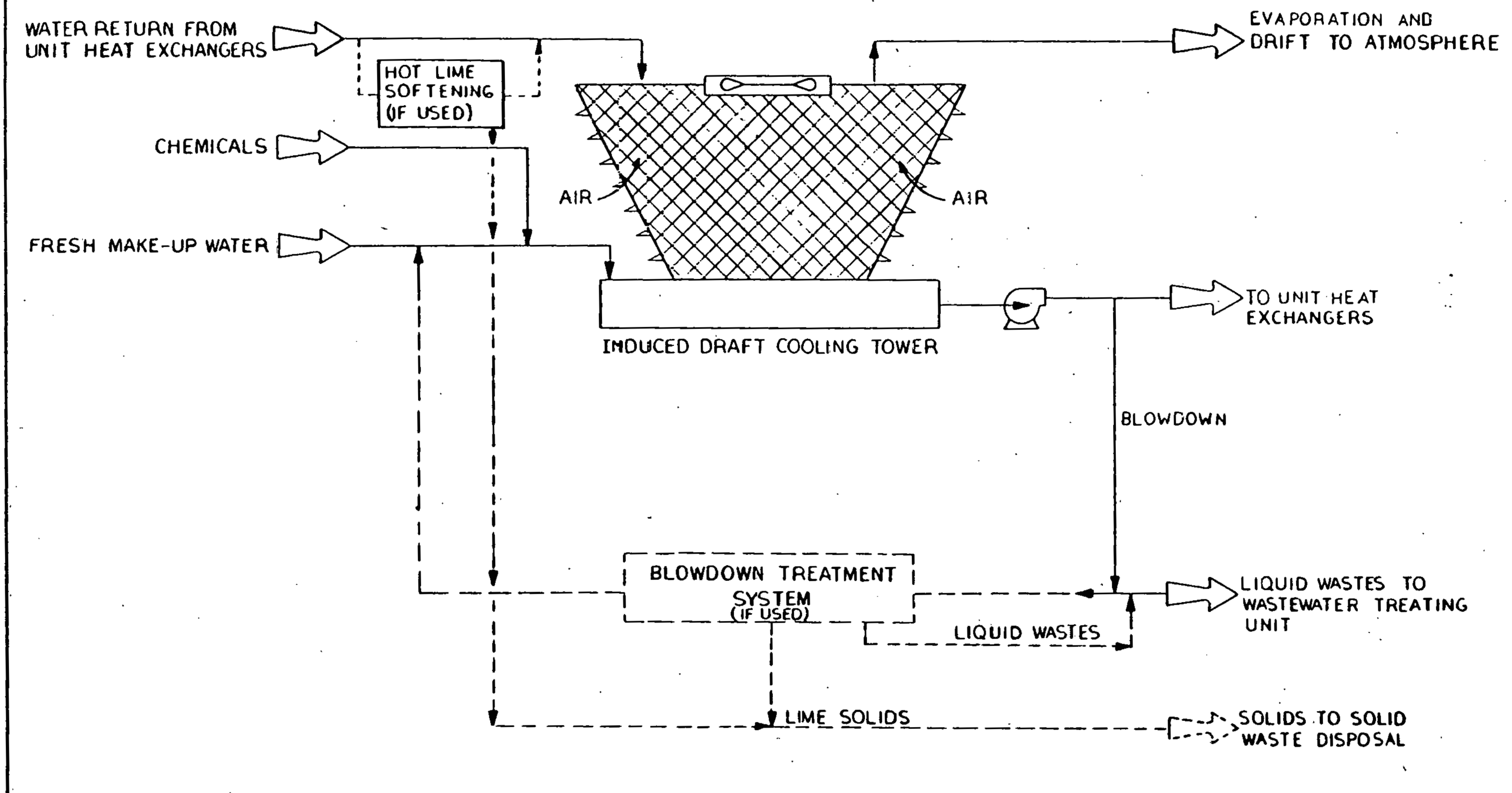


While the flare system is principally to relieve the hydrocarbon vapors from the process units, the blowdown system is designed to handle the liquid discharges. The blowdown system consists of the liquid relief valves (which release liquid materials during process upsets) and the unit pumpout systems which collect material that is purposely removed from the units. Pumpouts usually occur during start-ups and when the unit is coming down for maintenance. Pumped out liquid hydrocarbons are collected in slop oil tankage for reprocessing. This system avoids the uncontrolled discharge of hydrocarbons to the wastewater treatment system, the loss of expensive petroleum materials, and the release of hydrocarbon vapors which may cause air pollution.

2.18.4 Cooling Water System

Water is used as the typical medium for removing heat from the various refinery streams. Refinery cooling water systems are normally recirculating systems, which employ heat exchangers and cooling towers. A typical open, recirculating cooling system is shown in Figure 28. Water from the cooling tower basin is circulated to the process heat exchangers where it picks up heat and is returned to the cooling tower. The hot water is pumped to the top of the tower and is allowed to flow downward through the tower. The tower, which is open to the atmosphere, typically contains a wood or plastic packing which provides the surface area necessary to maintain high heat transfer efficiency. Atmospheric air is either forced, induced or flows by natural convection counter-current to the water flow and the water is cooled by evaporation of a portion of the water into the air flow. The cooled water is collected in the cooling tower basin and is pumped back to the process heat exchangers. Utility water or excess steam condensate is added as makeup to the basin to replace water lost by evaporation, drift, and to blowdown. In large refineries, the cooling water requirements are substantial and multiple cooling towers are used.

FIGURE 28
RECIRCULATING COOLING WATER SYSTEM



Due to the evaporation of the water, inorganic salts, such as calcium and magnesium sulfates and chlorides, will be concentrated in the circulation water. The salts can deposit in lines and heat exchangers, thereby reducing system heat transfer efficiency. While chemicals are added to control the deposition of these salts, a blowdown (or purge) stream is still required. In many cases, the blowdown volume can be large and may put a significant additional load on the wastewater treatment system.

To reduce the volume of blowdown, the "zero" blowdown or sidestream treatment concept is currently used in many refineries. In this system, either a side-stream of the return water or the blowdown is treated by such methods as lime-soda softening, ion exchange, evaporation, or reverse osmosis, to remove the dissolved salts. This allows the majority of the blowdown to be returned to the system, and only a purge stream of concentrated brine or lime solids must be handled as a waste. The use of a high quality makeup water or makeup water pretreating can also reduce the required volume of blowdown.

As an alternative to the conventional open recirculating cooling system, closed recirculating cooling systems may be used. In these systems, the hot water returning from the process exchangers is retained inside a heat exchanger located within the tower. Air, in the case of a dry tower, is passed over the exchanger coils, thus cooling the liquid inside without evaporation. This system also allows for heat transfer fluids other than water to be used as the fluid is maintained in a closed system.

Open and closed and wet and dry systems all have certain operating advantages and process cooling needs will dictate the type of system employed.

2.18.5 Receiving and Distribution Systems

Receiving and distribution systems are a combination of pumps, pipelines, tanks and loading facilities which are used to collect and store crude oil and store and distribute final products to trucks, barges, and other transportation. The receiving and distribution systems usually include an extensive vapor recovery system to collect the hydrocarbon vapors generated during the loading and unloading process.

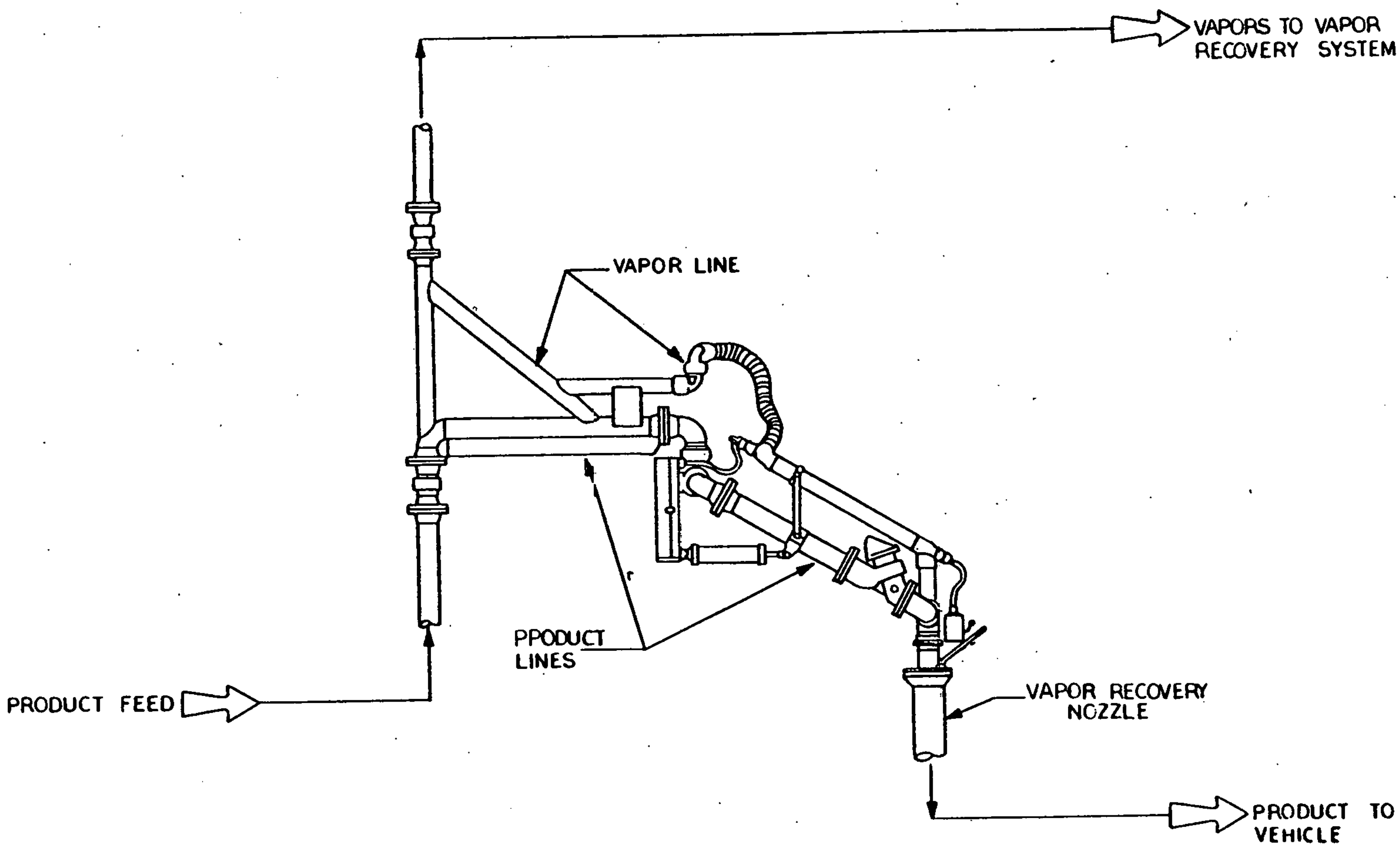
Receiving and Distribution Systems - Inland Refinery

Crude oil to an inland refinery usually arrives by pipeline. The oil is received in designated crude oil tanks that are sized to handle and store the volume crude oil necessary to maintain feed to the crude oil distillation unit. Other materials, such as cat cracker feed, may also be received from other refineries by pipeline, rail, barge, or truck and are also stored in tankage.

The finished products are stored in tankage until they are distributed. This is achieved by pumping from refinery storage tanks to a loading terminal where the products are loaded into seagoing tankers, tank cars, barges, and tank trucks by means of loading racks. The loading racks are structures containing the platforms, piping, vapor collection and control devices, and loading arm assemblies required for transferring the product from storage to the transport vehicle. Bottom loading, where the material enters the vehicle from the bottom, normally requires simpler equipment than overhead loading due to the fact that less hydrocarbon vapors are generated.

To avoid atmospheric pollution, the produced vapors are collected at the tank vehicle hatch using specially designed closure devices. An overhead loading arm is shown in Figure 29. For overhead loading, these are plug-shaped devices that have a central channel for the liquid to flow into a tank and an annular space for the vapor to flow out of the tank into a pipe connected to a vapor recovery system. For bottom loading, the material enters the bottom of the vehicle and a

FIGURE 29
TYPICAL TOP LOADING ARM FOR VAPOR RECOVERY



vapor take-off is connected between the vapor space of the vehicle and a vapor recovery system. This is shown in Figure 30.

The vapor recovery system may be a compression-type system and the recovered vapors fed directly to the fuel gas system or an absorption-type system using a hydrocarbon absorbent. A typical gasoline loading rack absorption system using gasoline as the absorbent is shown in Figure 31. As shown in the figure, gasoline vapors are recovered by absorption in gasoline. Vapors from the vehicle are sent through a flash arrester to a saturator where it is saturated with gasoline vapors. This is required to avoid explosive mixtures of hydrocarbons in air and is accomplished by countercurrent contact of the air-vapor mixture with gasoline in the saturator prior to storage in the gas holder. The vapors pass through a gas holder and scrubber and are then compressed, cooled and introduced into an absorption column where absorption of the hydrocarbon in gasoline takes place. The air is vented from the absorber to a flare system. The gasoline is returned to storage after the dissolved air is removed in the two-stage flash separator. The design recovery of hydrocarbon vapor by this system is in excess of 90 percent.

Receiving and Distribution Systems - Coastal Refinery

The crude oil receiving system for a coastal refinery will contain a marine navigation and an oil movement system. The marine navigation system deals with the guidance, movement, and maneuvering of tankers starting from an approach point in the open sea and continuing until they are tied up at a berth and connected to unloading facilities. The oil movement system conveys the crude oil from the tanker to intermediate storage and on to the processing units of the refinery.

The marine navigation system will consist of equipment and procedures to ensure the safe transit of tankers from the open sea to its berth and the equipment and structures to handle the vessels and load/unload the crude oil. The component parts include Coast Guard assistance and navigation aids varying in sophistication from buoys and

FIGURE 30

BOTTOM LOADING VAPOR RECOVERY SYSTEM

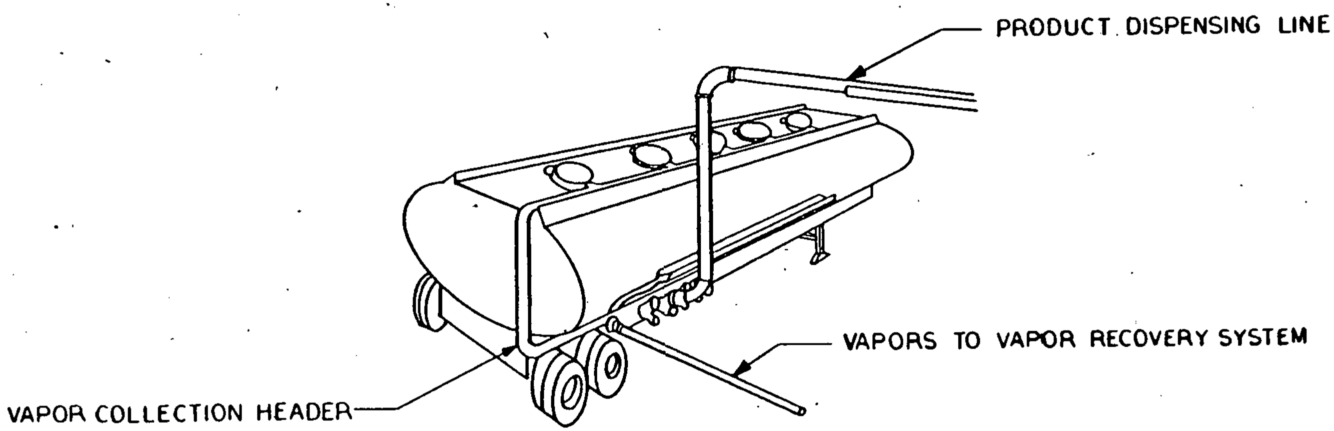
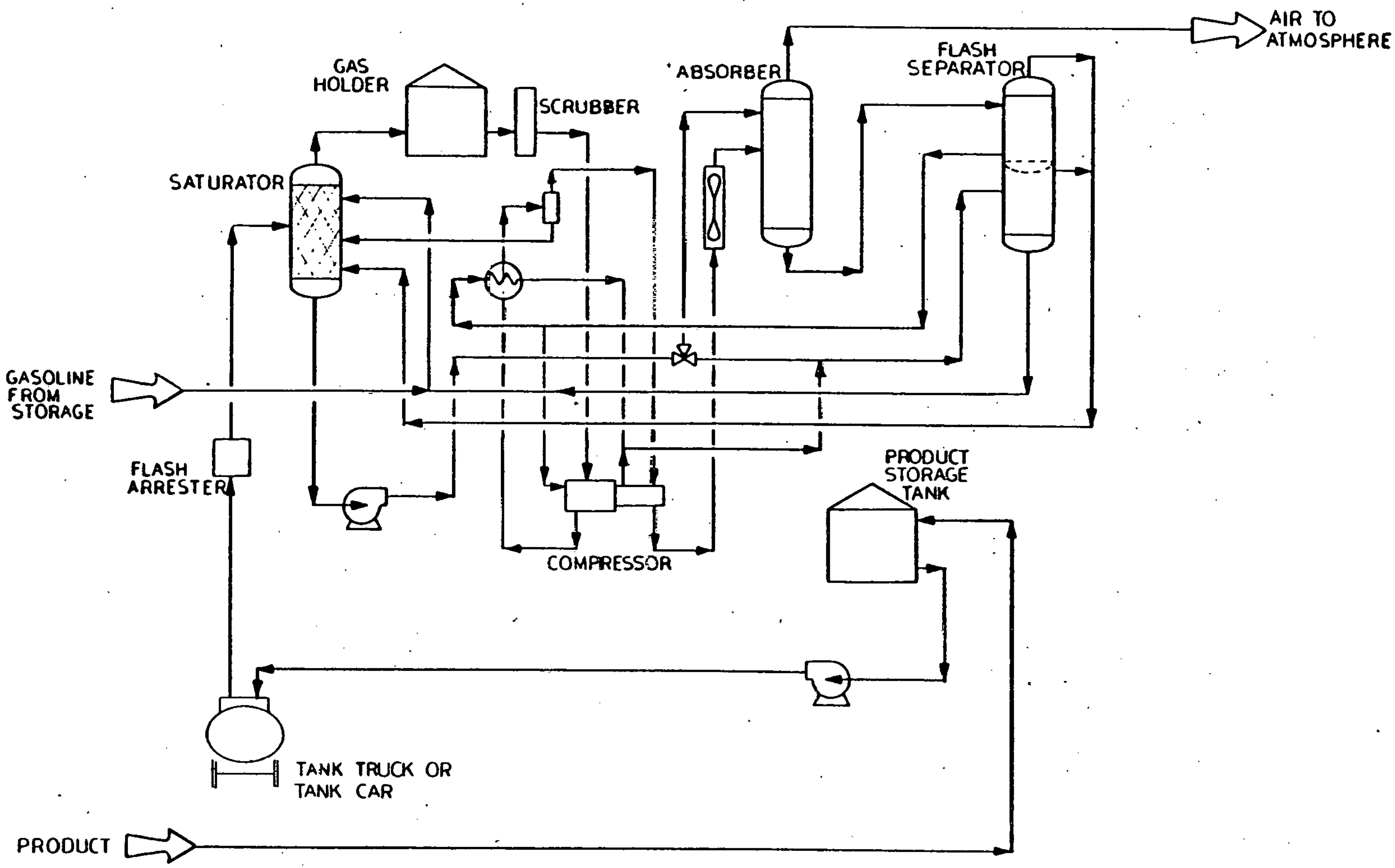


FIGURE 31
LOADING RACK VAPOR RECOVERY SYSTEM



markers to electronic guidance units and radio communications. Berthing procedures provide control of the vessel's movement to and from the site and include visual and electronic control systems, tugs and administrative procedures such as minimum acceptable weather conditions.

The oil movement systems will consist of equipment and structures to ensure the safe transfer of the crude oil and petroleum products. The pier design must reflect the best engineering practice and conform to local marine and refinery needs. Unloading/loading facilities consist of pipelines operated hydraulically and utilize quick connect/disconnect couplings. Spill prevention and control should be inherent features on the pier structure. Loading platforms typically are curbed and watertight and crude oil, product, and ballast water lines are counterbalanced units with swivel joints.

Oil spill containment and recovery is an important feature of the marine terminal. Oil spill response plans are required of the refinery to document spill control procedures. In many refineries, each vessel is surrounded by a boom after berthing to contain the oil if it should enter the water. On the berths, containment curbs and pumpouts are used to control any spill from entering the water. Sorbents are also normally available for spill control.

Spill cleanup procedures involve oil removal and restoration. Equipment used for oil removal include skimmers, vacuum pumps, absorbents, and herding agents. Restoration procedures involve the assignment of staff to remove deposited oil material and proper disposal.

Predicting the movement of vessels to transport the crude oil and refined products for a refinery on a coastal site is very site-specific and subject to a great deal of variability. The size of the tankers for both crude and product shipping, and the percentage of products moved by ship, pipeline, rail, or truck are the most sensitive parameters to marine traffic considerations. As an example of tanker movement, the environmental impact statement* for a proposed 250,000 BPD east coast refinery using tankers for all crude and product shipments listed the estimated annual tanker traffic. These data are summarized in Table 1. This is an extreme case representing the upper limit of tanker traffic as the site is isolated and without a local distribution center for the final products. The actual tanker traffic will depend upon such factors as refinery capacity and the extent to which other forms of transportation, such as truck or rail, are utilized to move the products. Smaller refineries or whose products supply a large local market may have only minimal tanker activity.

Table 2 shows the sizes of various tankers. The characteristics of the harbor will be a major factor in determining the size of the tankers that can be accommodated and thus can affect the amount of feedstock and product that can be moved by tanker. The size of the tankers will in turn affect the characteristics of the marine terminal in terms of loading and unloading capacity and dockside tankage requirements. Measures such as submerged off-shore storage tanks may be used for product and crude oil storage should harbor facilities be inadequate.

2.18.6 Gasoline Blending System

Finished gasoline is a mixture of various components produced by the refinery unit processes. These components must be blended in the proper proportions in order to meet the specifications of the final product. The mixing of these components is accomplished in an in-line blending system, shown in Figure 32.

Gasoline blending components are fed, through a system of metering pumps and control valves, to the gasoline blending heater. The metering pumps assure that each component is fed in the proper

*Final environmental impact statement for the construction of a 250,000 barrel/day oil refinery and marine terminal, U.S. Environmental Protection Agency, Region I, Boston, MA, June 1978.

TABLE 1

TANKER SIZES PLANNED AND

ESTIMATED ANNUAL SHIPMENTS*

Petroleum Material	Planned Tanker Size(DWT)**	Annual Tanker Shipments
Crude Oil	250,000	49
Gasoline	40,000	52
No. 2 Fuel Oil	70,000	56
No. 5 Fuel Oil	70,000	72

*Refinery Size = 250,000 BPD
**DWT = Capacity of Tanker in Dead Weight Tonnage (Long tons)

TABLE 2

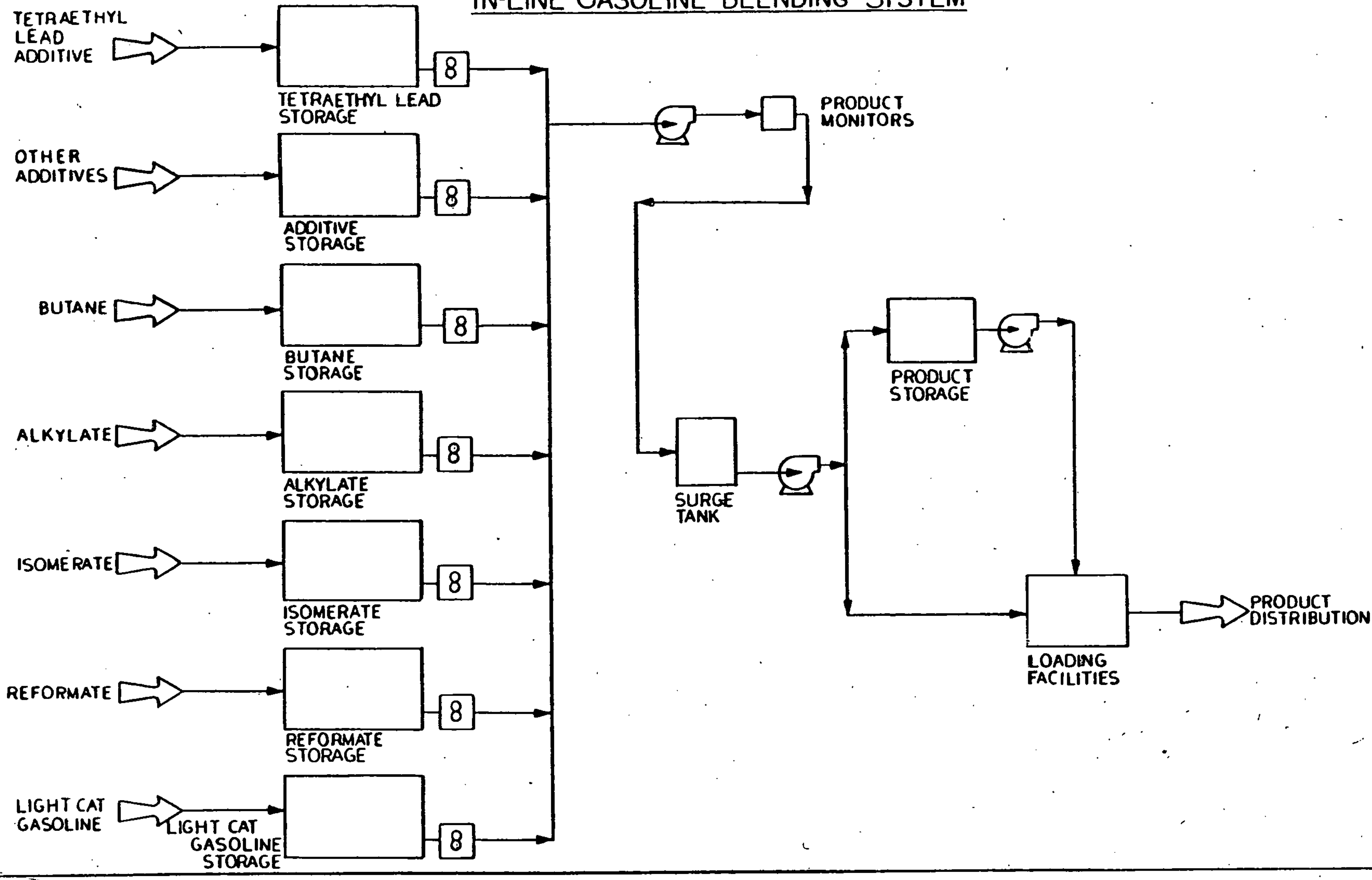
TYPICAL TANKER DIMENSIONS

Capacity (DWT)	Length (ft)	Draft* (ft)	Beam** (ft)
16,500	532	30.6	70
100,000	861	49.6	125
250,000	1140	65.4	170
500,000	1300	82	233

*Draft = depth of water displaced when fully loaded
**Beam = vessel width

FIGURE 32

IN-LINE GASOLINE BLENDING SYSTEM



proportion. The components are mixed by the flow turbulence in the header and fed to a series of on-stream analytical instruments which continuously monitor such product parameters as research and motor octane and vapor pressure. The product monitors automatically control the metering systems to maintain the proper proportion of each component.

The blended gasoline then passes to a surge tank which dampens flow surges but does not provide product storage. From the surge tank, the product can go directly to the loading facilities or be pumped to product storage.

A similar type system is used for the blending of fuel oils and distillate products such as jet and diesel fuels.

2.18.7 Fire System

While refinery fires are very infrequent, most refineries are completely equipped to fight a fire should it occur. The refinery fire water system is a separate water system with designated storage tanks, pumps, and piping system. Process areas maintain a system of permanently installed water spray devices called monitors, which provide virtually instantaneous fire fighting capability. Sewer systems, particularly in processing areas, are designed with seals, covers, traps, fire baffles, etc. to prevent the spread of fire between processing areas. In addition, the refinery maintains a foam system, fire trucks and other fire fighting equipment as well as fire fighting crews, consisting of trained refinery personnel. In general, most refineries are fully capable of handling any fire that occurs and internally provides virtually all required fire protection. Possible exceptions may be smaller refineries (less than 50,000 barrels per day of crude oil charge) which may require assistance from municipal and county fire departments. However, the first line responsibility for firefighting will remain with the refinery staff.

3.0 OVERALL PLANT DESCRIPTION AND CHARACTERIZATION

3.1 REFINERY DESCRIPTION AND COMPARISONS

For purposes of this workbook, data have been developed for ten specific refinery cases. These cases are divided into two refinery types. The first type is designed to maximize the production of gasoline and the second type is designed to maximize the production of fuel oil. The two refinery types have each been further detailed into configurations processing sour and sweet crude oils. The sour crude oil plants are all based on a crude oil feed containing 1.5% (wt) total sulfur, and sweet crude oil cases are based on a crude oil feed that contains 0.5% (wt) total sulfur. For the maximum gasoline-type refinery, cases were developed for crude oil feed rates of 200,000 and 100,000 barrels per day. For the maximum fuel oil refinery, capacities included were 200,000, 100,000, and 30,000 barrels per day. Table 3 summarizes these cases.

The flow diagrams for the maximum gasoline and maximum fuel oil refineries processing sour and sweet crude oil are shown in Figures 1 through 4, Section 1.2. These figures represent viable configurations for these plants. The actual configuration of any refinery is dependent upon a number of variables and these figures should not be considered to be identical to new plants that may be built to produce gasoline or fuel oil, but represent a workable plant concept that would allow sufficient operating flexibility.

In comparing the configurations of the gasoline and fuel oil refineries processing sour crude oil (Figures 1 and 3), it can be seen that the gasoline refinery is considerably more complex than the fuel oil refinery for processing the identical crude oils. The major difference between the plants is that the gasoline configuration includes such process units as hydrocracking, fluid catalytic cracking (FCCU), delayed coking, and alkylation, which are not required in the fuel oil case. These additional units are required to crack the heavier crude oil fractions into the lighter gasoline components and thus maximize

TABLE 3

REFINERY CASES STUDIED

Crude Feed Rate, Barrels/Day	Maximum Gasoline		Maximum Fuel Oil	
	Sweet Crude	Sour Crude	Sweet Crude	Sour Crude
200,000	x	x	x	x
100,000	x	x	x	x
30,000			x	x

the production of gasoline. Additional reforming capacity is also required to treat product streams from the hydrocracking and fluid catalytic cracking units.

In the fuel oil refinery, the cracking processes are not required, as the heavier crude oil fractions are blended directly into distillate and fuel oil products. Therefore, the fuel oil refinery will be less complex.

3.1.1 Comparison of Processing Sour vs Sweet Crude Oil

Sour Crude Oil and Sulfur Content

As discussed in Section 1.3, there are numerous definitions of sour and sweet crude oil. For our purposes, crude oil has been termed "sour" if it contains more than 0.5% (wt) of total sulfur. However, while the use of total sulfur content to define sour and sweet crude oil is common, it is not entirely correct. Strictly speaking, "sour" refers to the corrosivity and toxicity of the crude oil, and not the overall sulfur content. A sour crude oil is strictly defined as containing 0.5 ft^3 or more of dissolved hydrogen sulfide (H_2S) per 100 gallons of oil.[2*] Therefore, "sour" is related to only a portion of the total amount of sulfur that may be present in the crude oil. Based upon the preceding discussion, it is, therefore, possible to have a sour crude oil that is relatively low in overall sulfur content. Conversely, a high sulfur crude oil may not necessarily be considered as being sour, if the sulfur is present in forms other than as H_2S.

However, sulfur in all forms can cause operating problems and must be removed from the crude oil. In addition, hydrogen sulfide can be produced in the desulfurization process units, through the reaction of sulfur and hydrogen. Therefore, since the total sulfur

*Superscript indicates numbered reference.

in the crude oil must be considered in the overall processing scheme, a crude oil high in total sulfur is often termed "sour" and thus the definitions presented in this workbook are reasonable.

- Effect of Sulfur on Process Configuration

The total sulfur content and the H_2S contained in the crude oil has an effect on the configuration of the refinery, the materials of construction used in the process units, and the size of the pollution control units needed to control sulfur emissions.

In comparing the sour and sweet gasoline refineries (Figures 1 and 2), the major difference is that in the refinery processing sweet crude oil the mid-distillate and gas oil fractions from the crude oil distillation unit are not subjected to hydrotreating prior to further processing. This is because hydrotreating, a process used for removing sulfur from the crude oil fractions, is not required for certain fractions when processing sweet crude oil.

The same basic difference appears when comparing the maximum fuel oil refineries processing sour and sweet crude oil (Figures 3 and 4). Again, the sweet crude oil refinery does not require hydrotreating of the mid-distillate or gas oil fractions from the crude oil distillation unit. In addition, the sweet crude oil configuration would not require a hydrogen production plant, as sufficient hydrogen to meet refinery needs is produced by the heavy naphtha reforming unit.

The hydrotreating units which are common to both the sour and sweet crude oil refineries will be larger in the sour crude oil plant to provide greater hydrotreating severity due to the higher degree of sulfur removal required. This will also require that the hydrogen plant be larger, in order to provide the hydrogen necessary for the hydrotreating processes.

Sour crude oils are also more corrosive to process piping and equipment than is sweet crude oil. Therefore, refinery units processing sour crude oils will be constructed of special corrosion resistant alloys to minimize the corrosion caused by the sulfur compounds, particularly H_2S. The use of these alloys increases the refinery cost.

In terms of pollution control units, for plants of equal capacity, refineries processing sour crude oil will require more capacity in such units as sour water strippers, acid gas treating units, sulfur recovery plants, and tail gas treating units. The sour water stripper will be larger because more sour water streams will be produced and a larger quantity of hydrogen sulfide will be stripped from the water. Additional stripping steam will also be required to accommodate the increased stripping requirements. Similarly, the acid-gas treating unit will be larger as more acid-gas with a higher sulfur content must be handled. Since more sulfur is present, the sulfur recovery and tail gas treating units will also be larger to accommodate the increased sulfur loading. In addition, systems must be added to control the release of hydrogen sulfide from tanks and sewers to avoid potential problems of toxicity and flammability. The wastewater treatment unit will not be substantially affected by the sulfur content of the crude oil.

While some small refineries are being built to process sweet crude oil, or crude oils that have been previously desulfurized, it is unreasonable to assume that large refineries for processing only sweet crude oil would be considered for construction. Sweet crude oils are becoming less available and the uncertainty of foreign supplies of any crude oil is always a major consideration. While it is possible to process sweet crude oil through a sour crude oil refinery, the reverse is not true. The sour crude oil refinery configurations offer greater operating flexibility in terms of handling possible variations in the characteristics of the crude oil and would be the most likely candidate for construction. The sour crude oil gasoline refinery configuration shown in Figure 1 is the most complex and offers the greatest amount of operating flexibility. Conversely, the fuel oil refineries are more simple and would be the least flexible. Any actual refinery built would most likely fall somewhere between these two configurations, and would probably be designed to process sour crude oil.

3.1.2 Comparison of Processing Light and Heavy Crude Oils

In comparing the configurations of refineries of equal capacity but processing light and heavy crude oil, the principal differences are found in the sizes and types of the units used to process the various crude oil fractions. The refinery handling only light crude oil will have the greater capacity for processing the lower boiling range (light) fractions, while the heavy crude oil refinery will have larger capacity units for refining the higher boiling (heavier) crude oil fractions. If the primary purpose of the refinery is, for example, to produce light products, such as gasoline, the heavy crude oil plant will have extensive cracking facilities in order to convert the large portion of heavier fractions which are present into the more valuable lighter materials. In a light crude oil refinery, these units, if required, would be of lower capacity, as the proportion of heavy fractions available for cracking is less.

Light crude oils are becoming increasingly scarce and a growing proportion of the available crude oil is designated as being heavy. California, Canada, and Venezuela all have substantial reserves of heavy crude oil. Of principal concern when dealing with heavy crude oils is how to refine them using conventional refining equipment. These heavy crude oils will place severe demands on the flexibility of refineries and substantial equipment and process modifications may be necessary in order to process these crude oils.

As noted in Section 2.1, handling of heavy crude oil is difficult due to its high viscosity and high concentrations of sulfur and heavy metals. In addition, heavy crude oils contain only small amounts of low boiling range (light) fractions and conventional processing methods often produce only heavy products that have lower market value or, in some cases, are virtually unsaleable.[26] A number of methods are currently in use to process heavy crude oil and the choice of processing scheme will depend upon such factors as the characteristics of the crude oil and the refining processes available.

To upgrade these heavy crude oils so they may be handled by existing refineries and made into more valuable products, one technique is to hydrotreat the crude oil prior to distillation. This method of handling the heavy crude oil was derived from the recently developed technology which is used to hydrotreat the residuum from atmospheric and vacuum distillation units.

The hydrotreating of the crude oil can be done at the refinery, or possibly, in the oil field. The hydrotreating will effectively desulfurize and demetallize the crude oil and, most importantly, will lower the viscosity of the crude oil and increase the proportion of lower boiling range (light) fractions. This makes the crude oil easier to transport and allows for processing by existing conventional equipment. Table 4 shows an example of the properties of Canadian and Venezuelan heavy crude oils before and after hydrotreating. Due to the high concentrations of metals and sulfur in the heavy crude oils, catalyst replacement is more frequent than is required when processing light crude oils. Currently, these pretreating processes can handle crude oils with up to 600 ppm of heavy metals. However, work is continuing to develop hydrotreating catalysts that will tolerate higher metal concentrations.

While the treated (synthetic) crude oil still has a lower proportion of light fractions than its light crude oil counterpart, since it is now more amenable to conventional processing, the installation of additional fluid catalytic cracking or hydrocracking capacity can be considered in order to increase the proportion of light fractions produced.

TABLE 4

PROPERTIES OF UNTREATED AND HYDROTREATED VENEZUELAN AND CANADIAN HEAVY CRUDE OILS

	Venezuelan		Canadian	
	Untreated	Treated	Untreated	Treated
API Gravity	9.6	23.6	15.7	29.1-26.3
Viscosity SUV @ 210°F[a]	2650	60	-	-
Sulfur (wt %)	4.3	0.28	3.6	0.22-0.77
Metals (ppm) (Ni+V)[b]	468	27	20	3.0-30.0
Assay (Vol %)[c]				
C_5-375°F	<1	7.5	6	11-12
375-650°F	11	32	23	37-40
650-1050°F	39	43	37	39-33
+1050°F	49	23	34	15-16

[a]SUV = Saybolt Universal Viscosity
[b]Ni+V = Nickel + Vanadium
[c]Volume % within specified boiling range

Source: Reference 26

3.2 PLANT INVESTMENT

The construction of a refinery involves a large capital expense and the actual cost of a refinery is affected by many factors. Among the most important are:

- Refinery Complexity
- Sulfur Content of the Crude Oil
- Site Location.

The complexity of a refinery is related directly to the number and type of processing units in that refinery.* Refineries operating hydrotreating, catalytic cracking, hydrocracking and reforming units will be more complex than those that do not have these capabilities. For example, the gasoline refinery configurations shown in this document employ a greater number and a more varied mix of process units than do the fuel oil refineries, and are, therefore, more complex.

Refinery complexity also is an indication of refinery operating flexibility. The more complex facilities are able to process different crude oils more easily than those of lower complexity and are also more capable of shifting production from gasoline to distillate or fuel oil modes. This is because the more complex refinery has the additional process units necessary to handle a wide variety of crude oil fractions. The lower complexity plant does not incorporate these units and thus would not have this flexibility.

The sulfur content of the crude oil also has a significant effect on the refinery investment. As previously discussed in Section 3.1.2, special metallurgy for the process units, and additional sulfur removal capacity, are among considerations when processing sour crude oil. Data shows the cost of building a refinery to process sour crude oil [1.5% (wt) sulfur] is about 20% greater than an equivalent capacity refinery processing sweet crude oil [0.5% (wt) sulfur].[24]

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*Refinery complexity can be quantified using the procedure developed by W.L. Nelson. The method is discussed in Reference 24(I).

Site location also affects refinery investment. This is reflected in the regional variations in such items as construction wages, availability of materials, material costs, land and ready access to economical transportation methods. The costs given in this section reflect a Gulf Coast location, and other site locations may incur a different cost range.

The investment ranges for the ten refinery cases are shown in Table 5. These costs include process units and required off-site (support) facilities (wastewater treatment, tankage, piping, etc.). Also included is a factor for working capital. The working capital includes 30 days of crude oil storage at $40/BBL which is due to the uncertainty in foreign crude oil supplies and prices.

It is evident from the data in Table 5 that complexity has a significant effect on the refinery investment. For a given refinery capacity, the investment decreases with decreasing complexity. This is as expected as less process units are required in simpler refineries.

A different situation occurs when comparing the investments of various capacity refineries at a constant complexity. As the capacity of the refinery decreases, the investment per barrel of crude charge increases. This is because certain refinery cost items such as land, piping, buildings, and site preparation cost essentially the same for any refinery of a given complexity and are not proportionally affected by capacity.

Of the investments shown, pollution control facilities, including the sulfur recovery unit, tail gas treating unit, and wastewater treatment plant account for about 15% of the total cost. This percentage can vary depending upon such factors as sulfur content of the crude oil, if incineration of waste sludge is employed, and the extent to which other environmental control devices, such as scrubbers and electrostatic precipitators, are used. Of this 15% about one-third is for air pollution control facilities and two-thirds for water pollution control.

TABLE 5

REFINERY INVESTMENT (1979 Dollars)
(Gulf Coast Location)

Capacity (1000 BBL/Day)		$/BBL Capacity* 200	100	30	Total Cost (Millions)* 200	100	30
Refinery Type**	Complexity						
Gasoline							
Sour Crude Oil	11.5	5020-5650	6130-6950	--	1000-1130	610-690	--
Sweet Crude Oil	10.1	4120-4610	4930-5550	--	820-920	490-560	--
Fuel Oil							
Sour Crude Oil	5.9	3450-3820	4000-4460	5150-5810	690-760	400-450	150-170
Sweet Crude Oil	4.4	2780-3040	3080-3390	3820-4310	560-610	280-340	120-130

*Costs shown include process units and off-sites. Also includes working capital equal to 18% of process unit cost plus 30 days' crude oil at $40/BBL.
**For this document, sour and sweet crude oils are designated as containing 1.5% and 0.5% sulfur respectively (see Section 3.1.1).

Source: Mittelhauser Corporation

3.3 PLANT PROCESS UTILITY REQUIREMENTS

The utilities required by the various refinery types are:

- Steam
- Fuel (oil and/or gas)
- Electrical Power
- Cooling Water.

The steam is required for indirect heating of process streams using heat exchangers, driving pumps, and for direct process use such as steam stripping. Fuel, both oil and gas, is required primarily for combustion in high capacity heaters and boilers. The process heaters are used for heating process streams such as crude oil distillation and vacuum distillation unit feeds. Boilers are used to generate the steam required. Electricity is required for pumps, compressors, instruments and other equipment. Cooling water is needed to cool process streams both within the process and before they are sent to storage.

Typically, steam is generated on-site in a central boiler facility and is also supplemented by steam generated at certain process units such as the hydrogen unit and the fluid catalytic cracking unit. Fuel gas is produced by various refinery units, such as catalytic reforming, as a by-product of the unit operation and this source can be supplemented by purchased natural gas. Fuel oil can be either purchased or obtained from the fuel oil product produced at the plant. Electrical power usually is purchased from the local public utility but standby generating equipment may be available to maintain the operation of critical process units in case of a total power failure. Makeup water to the cooling water system can be obtained from any available water source. Some process wastewater streams can be also used as cooling system makeup.

The utility requirements for the ten refinery cases of this discussion are shown in Table 6. These data represent the utilities needed by the process operations only and do not include, for example,

TABLE 6

REFINERY UTILITY REQUIREMENTS

	GASOLINE REFINERY*				FUEL OIL REFINERY*					
	Sour Crude Oil		Sweet Crude Oil		Sour Crude Oil			Sweet Crude Oil		
Capacity($x10^3$ BBL/D)	200	100	200	100	200	100	30	200	100	30
Steam										
10^6 lb/Day	20.0-10.8	10.0-5.4	18.1-9.7	9.0-4.9	14.3-7.7	7.2-3.9	2.2-1.2	12.6-6.8	6.3-3.4	1.9-1.0
lb/BBL of Total Capacity	100.2-54.0		90.4-48.7			71.5-38.5			63.1-34.0	
Fuel										
10^6 BTU/Day	15.8-5.3	7.9-2.6	14.7-4.9	7.4-2.5	7.5-2.5	3.8-1.8	1.1-0.4	6.8-2.3	3.4-1.1	1.0-0.3
10^6 BTU/BBL of Total Capacity	0.8-0.4		0.7-0.3			0.4-0.2			0.3-0.1	
Electricity										
10^6 KWH/Day	1.8-1.2	0.9-0.6	1.6-1.1	0.8-0.5	0.9-0.6	0.5-0.3	0.1-0.09	0.8-0.5	0.4-0.3	0.1-0.08
KWH/BBL of Total Capacity	9.1-6.1		8.0-5.4			4.5-3.0			3.8-2.5	
Cooling Water**										
10^6 Gal./Day	554-238	277-119	538-230	269-115	249-107	125-54	37-16	240-103	120-51	36-15
Gal./BBL of Total Capacity	2770-1190		2690-1150			1250-540			1200-510	

*See Section 3.1.1 for a description of sour and sweet crude oil.
**Assume 20-30% temperature rise and represents process requirements for a recirculating cooling water system, fresh makeup water is normally less than 5% of the total process requirement.

Source: Mittelhauser Corporation

the requirements for heating or lighting of offices or control buildings. The ranges shown represent normal variations in the utility requirements for the individual process units. These variations account for options that the refinery designer has depending on site and process specific requirements.

As shown in Table 6, for refineries of different capacities, processing the same crude oil and producing the same major products, the required utilities will be proportional to the refinery capacity. For example, for the maximum gasoline refinery processing sour [1.5% (wt) sulfur] crude oil, the process utilities required for the 200,000 BBL/day plant are about twice that required for the 100,000 BBL/day facility. This is because the same process units are required in each plant, and the utilities required for each process unit are directly related to the individual unit feedrate. Since each process unit of the 200,000 BBL/day plant has essentially twice the capacity of the smaller plant, the total process utilities will be proportionally larger. The same analysis holds for the maximum fuel oil refineries of various capacities.

In comparing refineries of equal capacity, with the same primary product but processing crude oils with different sulfur contents, the plant processing sweet crude oil will require less utilities than the plant handling sour crude oil. This is due to the fact that the sweet crude oil plant does not have certain hydrotreating units and the utility requirements for the sulfur recovery and tail gas treating units have decreased in proportion to the sulfur content of the crude oil. In comparing the utilities required for processing a sour crude oil to those required for sweet [0.5% (wt) sulfur] crude oil, the reduction in utilities is 10 to 12% for steam, 7 to 10% for fuel, 12 to 15% for electricity, and 3 to 4% for cooling water.

Finally, in comparing maximum gasoline and maximum fuel oil refineries of identical capacities and processing the same crude oil, the maximum gasoline refinery will require about 30% more steam and 50%

more of the other utilities over that needed by the fuel oil refinery. This is due to the greater complexity of the gasoline refinery that is represented in the increased number of process units present.

The utilities required by the pollution control units are closely related to the sulfur content of the crude oil. This is because the pollution control devices with the largest utility demands are the sulfur recovery unit and tail gas treating units. Other pollution control units such as the sour water stripper, acid-gas treating unit, and the wastewater treatment plant all require utilities but do not have the large demand of the sulfur recovery plant.

For the sour crude oil cases, sulfur recovery and tail gas treating units account for 4-5% of the total fuel requirement and 4-6% of the total electrical power consumption. In the sweet crude oil cases, it is 1-2% of the fuel and 1-3% of the power. The other pollution control units together account for less than 1% of the total utilities, including steam and cooling water. The only exception may be for the wastewater treating unit if sludge incineration is used as the final disposal method. In this case, the wastewater treatment unit utilities may increase, but this would be on a case-by-case basis, depending upon the amount of sludge processed and the sludge characteristics. Any additional utility requirements due to sludge incineration would not be expected to be significant, in terms of the total refinery utility needs.

3.4 PLANT LABOR REQUIREMENTS

The labor requirements for a refinery are variable and are highly dependent upon such factors as refinery complexity, product mix, the refiner's staffing policies, and site location. These factors apply to both construction and operating labor requirements.

3.4.1 Construction Labor Requirements

The construction of a refinery requires the use of skilled, semi-skilled, and unskilled labor. Table 7 shows the construction labor by craft that are typically required for refinery construction. These data represent site preparation and construction of process units and refinery off-sites. The data also show the range of individual craft requirements as a percentage of the total manhours to complete the construction. This table is intended to show the general labor requirements for the various crafts needed for construction and the actual percentage of total manhours for each craft and specific crafts employed will depend upon individual site conditions.

Of the total required construction labor, engineering and design presents about 20% and craft and other direct manual labor accounts for the other 80%. As expected, pipefitters, boilermakers, iron workers, electricians, carpenters and laborers are the crafts accounting for most of the total project manhours since piping, process vessels, structural steel, electrical systems and concrete are basic to refinery construction.

Table 8 shows the manhours by craft for construction of example gasoline and fuel oil refineries. In comparing the overall construction manhours required for comparable sizes of gasoline and fuel oil refineries, the gasoline refinery, being more complex will require about 10% more overall manhours. However, the portion of the total hours expended by each craft is similar for each refinery, regardless of the capacity or complexity. This is because construction of process units and other

TABLE 7

CONSTRUCTION LABOR REQUIREMENTS*

Title or Craft	Percent of Total Project Manhours
Engineers, Draftsmen, Designers	22-23
Pipefitters	25-45
Electricians	11-13
Boilermakers	6-8
Iron Workers	5-16
Carpenters	7-16
Operating Engineers	6-8
Teamsters	2-4
Laborers	15-19
Bricklayers	2-4
Cement Mason	1-2
Insulator	3-9
Painters	1-3
Sheet Metal Workers	1-2
Millwright	1-3
Other (foreman, surveyors, etc.)	2-4

*Craft titles include all classifications (journeymen, helpers, etc.)

Sources: (1) Mittelhauser Corporation
(2) Reference 22

TABLE 8

CONSTRUCTION MANHOURS FOR VARIOUS SIZE REFINERIES

Craft	Gasoline Refinery 200,000 B/Day	Gasoline Refinery 100,000 B/Day	Fuel Oil Refinery 200,000 B/Day	Fuel Oil Refinery 100,000 B/Day	Fuel Oil Refinery 30,000 B/Day
Laborer	1,670,000	1,110,000	1,550,000	1,050,000	494,000
Carpenter	1,240,000	820,000	1,350,000	750,000	365,000
Teamster	340,000	255,000	320,000	210,000	103,000
Cement Mason	125,000	82,000	120,000	75,000	36,000
Operating Engineer	710,000	470,000	650,000	430,000	209,000
Pipefitter/ Welder	3,740,000	2,440,000	3,180,000	2,200,000	1,070,000
Boiler-makers	440,000	280,000	370,000	245,000	120,000
Iron-workers	670,000	440,000	600,000	395,000	195,000
Mill-wrights	160,000	95,000	110,000	69,000	35,000
Painters	170,000	110,000	155,000	105,000	50,000
Surveyors	120,000	107,000	110,000	102,000	67,000
Insulators	110,000	75,000	95,000	63,000	30,000
Total Manhours*	9,495,000	6,284,000	8,610,000	5,694,000	2,774,000

*Includes 70% efficiency factor.

Source: Ralph M. Parsons Company

facilities will require the same craft mix for installation regardless of overall plant size or complexity. Therefore, although the total manhours for construction may vary, the individual craft requirements are relatively constant.

Figure 33 shows a typical craft mix for certain crafts as plotted against elapsed construction time. As shown, the mantime requirements for each craft varies as the construction reaches various stages of completion. At 20% project completion, operating engineers f site preparation, carpenters for construction of concrete forms and laborers will be in greatest demand, with carpenters, for example, comprising 16% of the on-site construction labor. By comparison, at 75 project completion, the craft mix has changed significantly and pipefitters and electricians will comprise the bulk of the labor requirements. Again, these figures show only a general craft mix during construction and the actual craft mix at any given time for a specific refinery construction project may vary from these data.

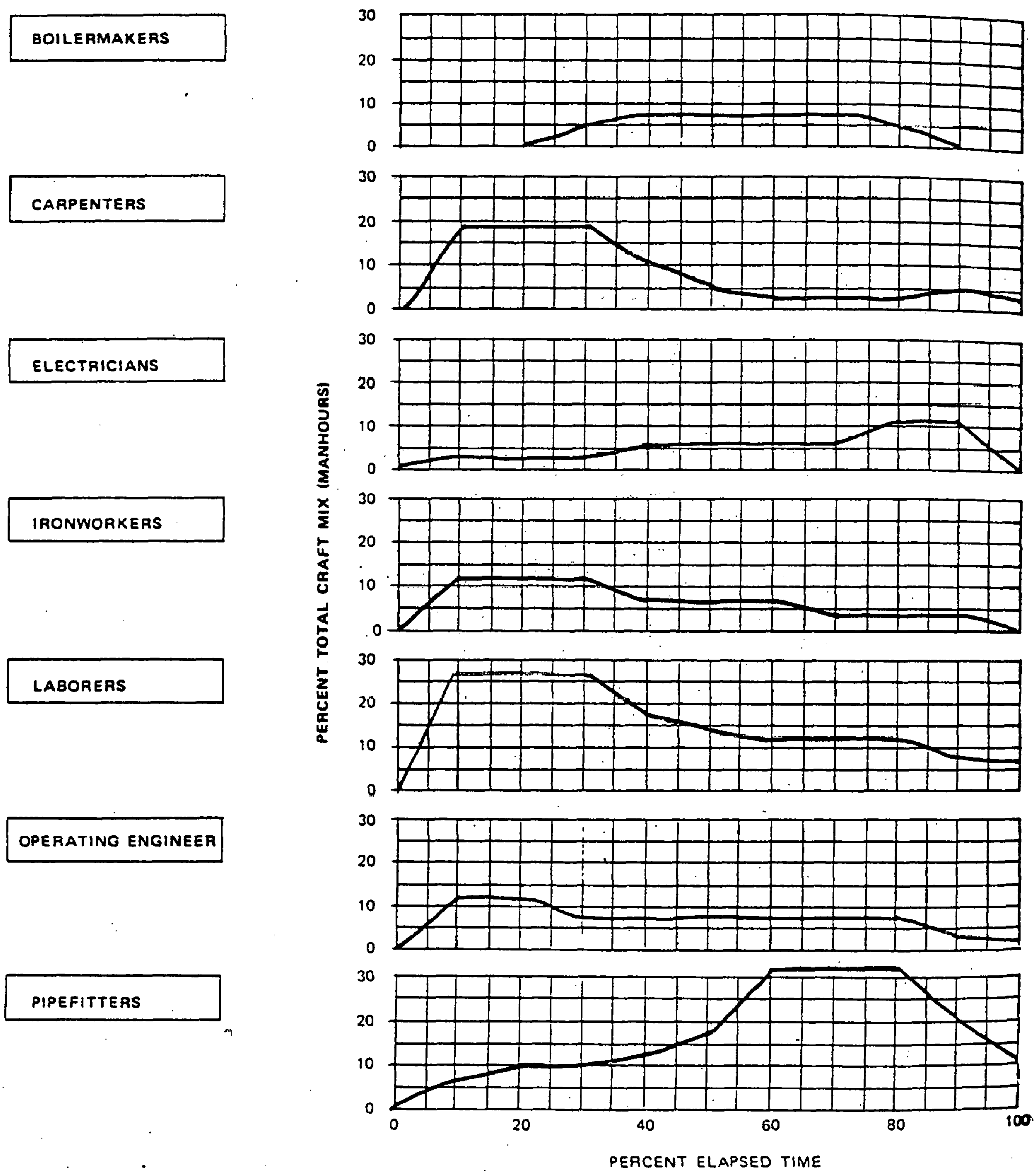
3.4.2 Operating Labor

Refinery operating labor is comprised of the process unit operators, maintenance, engineering and supervisory administrative personnel. The operating labor requirements of a specific refinery depend upon the refinery complexity, location, and if the refinery is owned by a major or independent oil company.

The overall operating labor requirements for the example refineries outlined in this document are shown in Table 9. These data includ process unit operators, operating supervision, maintenance labor and supervision and engineering, and administration. Of the total operating labor, unit operators represent 48%, operating supervision is about 7%, maintenance is about 37%, and engineering and others, is about 8%. These proportions are essentially the same for both major and independent refiners and regardless of plant complexity.

FIGURE 33

TYPICAL CRAFT MANHOUR DISTRIBUTIONS FOR REFINERY CONSTRUCTION



Source: Reference 23

TABLE 9

OPERATING LABOR REQUIREMENTS

Refinery Capacity (10^3 B/Day)	Major Refiner										Independent Refiner	
	200				100				30		30	
Refinery Type*/Crude* Oil Processed*	Gasoline/Sour	Gasoline/Sweet	Fuel Oil/Sour	Fuel Oil/Sweet	Gasoline/Sour	Gasoline/Sweet	Fuel Oil/Sour	Fuel Oil/Sweet	Fuel Oil/Sour	Fuel Oil/Sweet	Fuel Oil/Sour	Fuel Oil/Sweet
Process Unit Operators	371	278	212	167	222	203	103	104	82	68	49	41
Operation Supervisors 6	53	40	30	24	32	30	19	15	12	10	7	6
Maintenance Labor and Supervision	280	210	160	126	168	154	98	79	62	51	37	6 31
Engineering, etc.	54	48	36	29	38	35	22	18	14	12	8	7
TOTAL**	768	576	438	345	460	422	269	216	170	141	100	85

*See Section 3.1.1 for description sour and sweet crude oils.
**Actual labor may vary ±30% from total shown.

Source: Reference 22, pp 194-196

Major differences occur, however, in the actual number of operating personnel required for a given refinery. In general, in order to facilitate economical operation, an independent refiner will employ about 40% fewer operators and 20% fewer maintenance people than a major refiner for a refinery of equal capacity and complexity. An example of the actual manpower difference between major and independent refiners is shown in Table 9 for the 30,000 B/Day fuel oil refinery.

Table 10 is a listing of the various refinery jobs by general labor category. As with the construction labor, this list is intended to give an overall labor requirement and a specific refinery may not necessarily include all job titles that are shown here. The actual number of people required for each job for a given refinery will depend upon overall refinery configuration and the site specific wage and labor market conditions.

TABLE 10
REFINERY JOBS[a]

CATEGORY

ADMINISTRATION[b]

- Senior Staff Engineer
- Chief Process Manager
- Asst. Chief Engineer
- Refinery Manager
- Tech. Assistant to Manager
- Legal Counsel
- Superintendent
- Assistant Superitendent
- Secretaries
- Stenographers

ACCOUNTING[b]

- Office Manager
- Chief Accountant
- Chief Clerk
- Cost Accountants
- Economics Engineers
- Payroll Accountants
- Cashier
- Paymaster (Payroll Supervisor)
- Timekeeper
- Clerks
- Typists
- Telephone Operator

PURCHASING AND SALES[b]

- Shipping Dept. Supervisor
- Stock Dept. Supervisor
- Purchasing Agent
- Buyers

TECHNICAL SERVICES MANAGEMENT[b]

- Manager of Technical Services
- Technical Director
- Assistant to Technical Director
- Director of Research
- Assistant to Research Director
- Secretaries
- Clerks
- Engineering Consultants

ENGINEERING[b]

- Chief Mechanical Engineers
- Mechanical Engineers
- Chief Electric Engineer
- Electrical Engineers
- Civil Engineers
- Structural Engineers
- Maintenance Engineers
- Design Engineers
- Safety Engineers
- Head Draftsman
- Draftsmen
- Chief Process Engineer
- Process Engineer - Process Units

CATEGORY

LABORATORY AND TESTING[b]

- Chief Chemist
- Chief Technologist
- Chemist, Petroleum
- Chemist, Special Testing
- Chemist, Research
- Assistant Research Chemists
- Consulting Chemists
- Metallurgist

MANUFACTURING AND MANAGEMENT[b]

- Manager of Operations
- Night Superintendent
- Director of Operations
- Secretaries
- Area Supervisors
- General Foreman
- Shift Foreman

MANUFACTURE

- Chief Operator
- Process Unit Foremen
- Shift Foremen
- Unit Operators
- Assistant Operators - first helper
- Assistant Utility Helper
- Firemen
- Housemen
- Helper - second
- Helper - third

MAINTENANCE AND CONSTRUCTION

- Superintendent Construction & Maintenance
- Maintenance Supervisor
- Construction Foreman
- Maintenance Foreman
- Planning Foreman
- Craft Foreman (see below)
  - Asbestos and Paint Shop
    - Working foreman
    - Sign Painter and decorator
    - Painter, first class
    - Painter helper
    - Painter rough
    - Sand blaster
    - Cement finisher
    - Insulator
    - Insulator helper
    - Laborer
    - Common labor
  - Boiler Shop
    - Inspector
    - Layout man
    - Boiler maker, steel worker
    - Fitup man
    - Blacksmith
    - Blacksmith helper
    - Blacksmith apprentice
    - Tool-room man
    - Boilermaker helper
    - Second helper
    - Third helper

TABLE 10 (Contd)

CATEGORY

Carpenter Shop
- Gang foreman
- Maintenance carpenter
- Carpenter, first class
- Carpenter, helper
- Carpenter, rough
- Carpenter helper
- Form builder
- Car bracer
- Laborers

Electric Shop
- Electrical Foreman
- Maintenance inspector
- Maintenance electrician or lineman
- Electrician, temporary
- Lineman, temporary
- First Helper
- Second Helper
- Electric motor repairman
- Tele. troubleshooter
- Lamp washer
- Laborer

Instrument Shop
- Repair foreman
- Repairman
- First Helper
- Second Helper
- Meter repairman
- Gas governor repair
- Chartman or changer

Welding Shop
- Foreman
- Master welder(combination)
- Welder (combination)
- First Helper
- Second Helper
- Third Helper
- Arc welder
- Acetylene welder
- Material reclaimer
- Chipping, peening, etc.
- Lead burner (acid plant)
- Lead burner, B
- Lead burner helper
- Labor

Machine or Pump Shop
- Foreman
- Special Machinist
- First Class Machinist
- Second Class Machinist
- First Helper
- Second Helper
- Toolroom Man
- Valve Grinder and Machine Operator
- Molder
- Molder Helper
- Engine Repairman
- Master Mechanic
- Mechanic (Auto)
- Mechanic Helper
- Pump repairman
- Pump helper
- Truck Mechanic
- Laborers

CATEGORY

Sheet Metal Shop
- Tinner, first class
- Tinner, second class
- First Helper
- Second Helper

Pipe Shop
- Foreman
- Pipe fitter and welder
- Utility man or plumber
- Pipe machine operator
- Pipe bender
- Pipe fitter foreman
- Pipe fitter
- First Helper
- Second Helper
- Utility Pipe cutter

Cement and Brickwork
- Mason foreman
- Brick mason
- Plasterer foreman
- Plasterer
- Cement finisher
- First Helper
- Second Helper

Miscellaneous Labor
- Gang foreman - first class
- Gang foreman - second class
- Rigger - first class
- Rigger - second class
- Rigger - helper
- Maintenance man
- Third helper
- Fourth helper
- Crane operator
- Crane operator helper
- Utility labor
- Maintenance labor
- Maintenance labor - second class
- Casual labor
- Tractor operator
- Bulldozer operator
- Boiler washer
- Tower cleaner (trays)
- Reactor cleaner
- Tube cleaner
- Catalyst mixer
- Catalyst loader
- Fire equipment man
- Fire equipment helper
- Hoisting engineer
- Truck driver (winch)
- Truck driver under 2-1/2-ton
- Truck driver over 2-1/2-ton
- Truck driver helper
- Pipeliner, first class
- Pipeliner, second class

UTILITIES
- Power-house engineer
- Water-station engineer
- Water-station helper
- Boiler fireman
- Boiler operator
- Boiler helper
- Water tender or treater
- Electric Power Operator
- Electric Power Helper
- Water Pumper
- Cooling tower operator
- Air-compressor operator
- Water-softening operator
- Power-house oiler
- Power-house electrician
- Power foreman

TABLE 10 (Contd)

CATEGORY	CATEGORY

SHIPPING, RECEIVING, AND STORAGE

Superintendent, Receiving and Shipping[b]
Manager, Warehouse[b]
Manager, Marine Loading[b]
Supervisor, Receiving and Stores[b]
Storekeeper Chief
Stock Foreman or Keeper
Warehouse Record Clerk
Material (Stock) Clerk
Inventory Clerk
Dispatcher
Receiving Clerk
Shipping Clerk
Shipping Checker
Tool Clerk and Foreman
Tool Clerk
Order Filler
Barrel Weigher
Stenciler
Stenciler Helper
Head Barrel Filler
Head Can Filler
Yardmaster or Head Loader
Head Wharf Tender
Traffic Manager
Terminal Superintendent
Can Capper
Can Conveyor Feed
Container Washer
Warehouseman
Nailing Machine Operator
Drum Plant Filler
Floorman, Compounding
Caser
Asphalt Switching
Package Fillers - Hand
Package Fillers - Machine
Locomotive Fireman
Locomotive Crane Operator
Crane Follower
Head Transport Loader
Rackman (also see loaders)
Rackman Helper
Switch Tender
Brakesman
Elevator Operator, freight
Trucker, Hand
Truck Driver, under 2-1/2 tons
Truck Driver helper
Truck Driver, over 2-1/2 tons
Loaders (rail cars and trucks)

Heavy-oil loading rack -
Loader
Blender and Helper

Light-oil Loading rack
Chief Loader
Senior Clerk
Pumper or Top Loader
Ground Man or Helper
Gager

Boat Loader
Boat Loader Helper
Dock Loader (truck)
Container repairman
Container repair labor
Container inspector
Drum Conditioner Operator
Drum Conditioner Assistant
Drum Conditioner Helpers
Car (railroad) inspector

Tank-car Repair
Air brakeman
Steam coil
Repairman-foreman
Second helper
Third helper
Fourth helper
Labor
Cleaner

Boxmaker
Box printer
Cooper
Painter, barrel or container
Painter, spray
Painter, helpers
Salvage Foreman
Salvage Man
Salvage Helper
Reclamation inspector
Garageman
Fork-lift operator

PROTECTION AND CUSTODIAL SERVICE

Personnel and safety director[b]
Safety and Training Supervisor[a]
Physician, industrial[b]
Nurse, industrial[b]
First Aid Attendant[b]
Superintendent, Protection[b]
Guard sergeant
Guard captain
Guards (roundsmen)
Gatemen
Watchmen
Fire mashall
Fire inspector
Firemen
Janitor
Charwoman
Porter
Groundskeeper

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[a]Source: Reference 22, pp 67-68, 75-76
[b]Usually Salaried Employees

3.5 LAND REQUIREMENTS

The land requirements for a refinery are variable and are heavily dependent upon such considerations as land availability, environmental restrictions, proximity to residential areas, available rail and water access, available utilities (power, water, etc.) suitability of land for construction, and land costs.*

The final selection of a site requires the land be suitable for constructing process units, tank farms, loading facilities, and maintenance areas and the design and layout of the refinery will depend upon the existing surrounding area and overall land availability. If land is plentiful, a given refinery will tend to purchase more acreage to allow for future expansions and greater separation of process units, tankage and other areas. This allows for greater flexibility of adding on process units as well as increased safety in the event of fire. The availability of land can also affect land utilization. For example, if sufficient land area can be obtained, a refinery may consider on-site land farming of wastewater sludges or evaporation ponds for disposing of final effluents as alternatives to incineration, contract landfilling or discharge of treated effluent to a waterway. It may also be possible to allow a larger buffer area between the process units and plant boundaries if a large plot can be obtained.

Another aspect of land availability is in terms of environmental restrictions. Considerations such as the proximity of wildlife refuges, designated Green Belt areas, or areas with extreme air or water pollution requirements have a significant effect on land availability and development and use of the site. These restrictions can, for example, limit plot sizes and access to waterways or rail lines. In some cases, development of a site that requires greater construction effort and expense may be more desirable than building in an environmentally

*The socio-economic aspects of land requirements are discussed in Section 3.9.

sensitive area where the land may be more suitable to construction. These considerations will, however, vary for different sites.

The proximity of the proposed refinery to residential, agricultural, recreational and urban areas will be of prime interest to local landowners. Of major concern will be property values and possible aesthetic changes in the area. Refineries like other industrial plants can be, and are, constructed to blend with the surrounding landscape, by the use of earthwork and trees or other foliage to form Green Belt areas around the plant. Process units and other active areas are normally situated well within the plant boundaries to avoid direct contact with the surrounding area. Examples of refineries being compatible with its surroundings are the Texaco refinery in Anacortes, Washington, which has deer living within the plant boundary and the Mobil Oil refinery in Joliet, Illinois, which is located within two miles of a state game preserve.

Availability of utilities as well as access to transportation systems such as rail or water are also factors which affect refinery siting. If the local public works cannot supply the necessary utilities, they will have to be produced on the refinery site, which entails additional capital and maintenance expenses. Such concerns as rail, water, and even truck access are also important when determining the logistics of moving both raw materials and finished products. If acceptable transportation facilities are not available, this could also result in additional construction costs or bypassing a given site in favor of another.

The suitability of the site for construction is also an important consideration. The process units, tanks and product and raw material transportation vehicles will put a severe strain on the load bearing capability of the land. If the land is swampy for example, considerable land filling prior to construction may be required and construction may entail more extensive use of piles or caissons than if the site were situated on more stable ground. In addition, consideration is given to the potential for earthquakes, flooding, etc. These factors can result in additional construction expense and a marginal site can become uneconomic to develop. The effect of these and the other factors noted will have a different impact on each individual site and the considerations and concerns for site selection will be site-specific.

Historically when land was relatively inexpensive, refineries would typically obtain 15 to 20 acres per 1000 barrels of refinery capacity at the time the refinery was built.[33] This would generally include some land for expansion, but additional land would also be obtained as the early refinery increases capacity. More recently, due to the rising costs of land, the average land requirement for new refineries has been reduced to about 5 acres per 1000 bbl of capacity.[24(G)] For the example refineries of the complexity shown in this document, due to the necessity for the storage of intermediate products, it may be assumed that the gasoline refinery will require about twice as much land as the fuel oil refinery.[33] Using the average of 5 acres per bbl of capacity, Table 11 shows the total estimated acreage required for the example gasoline and fuel oil refineries shown in Table 3, Section 3.1. Of this total acreage, about 10% is required for the process units, land for tankage typically is about 26% of the total,[24(G)] depending upon such factors as product mix, operating conditions, product distribution system, and storage capacity requirements. The remaining area is used for expansion, Green Belt areas, buffer zones and other uses. It should be noted that the estimated land requirement for refineries, manufacturing similar products, but processing sweet or sour crude oil, are equal. This is because crude oil characteristics principally affect the process units, which require the minimum land space. Land for tankage and other uses is not affected as greatly by the characteristics of the crude oil.

The land actually utilized by four existing refineries is shown in Table 12. Because of the different site conditions, the

TABLE 11

ESTIMATED LAND REQUIREMENTS FOR EXAMPLE REFINERIES

Type of Refinery	Gasoline				Fuel Oil					
Type of Crude Oil*	Sour		Sweet		Sour			Sweet		
Capacity (1000 B/Day)	200	100	200	100	200	100	30	200	100	30
Total Land Area (Acres)	1000-2000	500-1000	1000-2000	500-1000	500-1000	250-500	75-150	500-1000	250-500	75-150

*See Section 3.1.1 for description of sour and sweet crude oil.

TABLE 12

LAND REQUIREMENTS OF FOUR EXISTING REFINERIES

		Land Requirements (acres)				
Refinery	Capacity (1000 B/Day)	Process Units	Tankage	Planned Expansion	Other	Total
A	360	160	277	80	383	900
B	160	70	250	70	310	700
C	78	60	140	120	680	1000
D	30	4	16	5	25	50

Source: Mittelhauser Corporation

total land usage is extremely capable. Land usage ranges from 2 to 13 acres barrel of capacity and is site dependent. For example, refinery A, processing 360,000 bbl/day is located in a highly urban area. In contrast, refinery C, which is only about 20% as large as refinery A, is located in a more remote area and has about 10% more land area than refinery A. Also shown in the table is the land utilization by the various refineries. Of the total acreage, 10% to 20% of the land is used for the process units, 20 to 35% is for tankage, 10% is for planned expansion, and the remainder is undesignated. The undesignated land may be used for such purposes as land farming of wastewater treatment sludge, buffer areas between the process units and plant boundaries and Green Belt areas surrounding the parameter of the plant. These divisions represent the land usage for these four existing refineries, and should not be considered as necessarily typical of all refineries. The actual land utilization will depend upon local site conditions.

3.6 PLANT WASTE PRODUCTION

As is the case with other industrial plants, refineries will generate air emissions, and aqueous and solid wastes. The production of these wastes is an unavoidable part of the oil refining process and measures have been developed to minimize the production of these wastes and to treat the wastes that are generated. Generation of the wastes is minimized by maximizing process unit efficiency, and extensive waste treatment is included as part of all refineries to handle and treat the wastes that are produced.

3.6.1 Air Emissions

The amount of emissions released to the atmosphere from a refinery is dependent upon many factors including the type of crude oil being processed, the complexity of the refinery, and the types and characteristics of the fuels used by the processing units. For example, a refinery processing heavy crude oils will require more heating capacity to process the crude oil than a light crude oil refinery and thus will burn more fuel and have a higher emission rate. Likewise, a highly complex refinery will have more processing units and thus a greater number of emission sources. Finally, a refinery burning fuel oil as a process fuel will have more emissions than a refinery using fuel gas as its major process fuel source.

The major air emissions from a refinery are:*

- Particulates
- Sulfur Oxides (SO_x)
- Carbon Monoxide (CO)
- Hydrocarbons
- Nitrogen Oxides (NO_x)

and can be generated by both process units and off-site facilities.

*For this document, SO_x is taken to be sulfur dioxide (SO_2) and NO_x is nitrogen dioxide (NO_2).

The major sources of air emissions within a refinery are:

- Process Heaters
- Steam Generation System
- Fluid Catalytic Cracking Unit Catalyst Regenerator
- Sulfur Recovery Plant Tail Gas
- Miscellaneous Sources.

Process heaters (or furnaces) are, collectively, the major sources of air emissions from a refinery. These heaters are used to heat the crude oil and other streams to the temperatures required by the processing units. They are most frequently used on the unit feed streams but may also be used between stages within a process unit (i.e., catalytic reforming units).

Since fuel gas is an overall, cleaner burning fuel than fuel oil, most refineries will use fuel gas (supplemented with natural gas when necessary) as the major source of process heater fuel. Federal regulations limit the amount of H_2S that can be present in fuel gas to 0.1 grains H_2S/DSCF. Since the gas does not contain particulate matter or nitrogen compounds, overall emissions from fuel gas combustion are very low, most refineries do not require emission control for gas-fired equipment.* A different situation may exist if fuel oil is used as the main process heater fuel. Depending upon the gravity and sulfur content of the fuel oil, flue gas treatment to control particulate and sulfur emissions may be required for oil-fired process heaters.

The refinery steam generation system, which produces the bulk of the steam used in the refinery, can also be a significant source of air emissions. Combustion of the fuel in the boilers is the emission source and, like other fired heaters, the emissions depend upon the amount of fuel burned and the fuel characteristics. Federal regulations place limits on the emissions allowed from steam generators with heat inputs greater than 250 MM BTU/hr. Refinery

*See Section 4.0 for a complete discussion of the Air Emissions Control Regulations.

gas, some SO_x will be present in the tail gas released to the atmosphere. These amounts are small but nonetheless comprise an emission source.

Miscellaneous emissions typically are hydrocarbon emissions from such sources as storage tanks, uncovered oil separation tanks at the wastewater treatment plant, combustion emissions from the wastewater sludge incinerator and flares, and coke dust from the decoking operation. Storage vessels are equipped with vapor recovery systems and floating roofs to minimize these losses. Product loading facilities also are equipped with vapor recovery systems. Sludge incinerators have flue gas control devices and other fugitive emissions, particularly hydrocarbons, are controlled through proper unit operation and proper attention to housekeeping and maintenance.

The various sources of refinery emissions have been identified and emission factors have been determined. The factors used in this document are shown in Table 13. The fuel emission factors are used to determine the emissions generated by all fuel burning furnaces, heaters and boilers, including the refinery steam generation unit. Emission factors for the fluid catalytic cracking CO boiler and the refinery tail gas treating unit are also shown.

Using the emission factors shown in Table 13, the overall emissions from the ten example refineries is shown in Tables 14 and 15. These data are based on the fuel and steam requirements given in Table 6, Section 3.3, and assume that no emission controls exist on the process heaters or steam generating unit, and that the CO boiler flue gas is meeting the Federal New Source Performance Standards.[13] In an actual refinery, depending upon local regulations, fuel used and the boiler size, the steam generating unit may require control of stack gas emissions. This requirement would be, however, site specific.

As shown in Tables 14 and 15, the overall refinery emissions will vary with overall refinery capacity and crude oil charge characteristics (complexity) and process fuel used. These data assume that

TABLE 13
EMISSION FACTORS

	Fuel Oil[a] (lb/bbl)	Fuel Gas[a] (lb/1000 SCF)
Process Heaters		
Particulate	0.97	0.02
Sulfur Oxides (SO_x)	$6.72xS_o$[b]	$2xS_f$[b]
CO	0.168	0.017
Hydrocarbons	0.168	0.029
Nitrogen Oxides (NO_x)	1.68	0.23

Fluidized Catalytic Cracking Unit - Catalyst Regenerator (w/CO Boiler)	
Particulate[c]	1 lb per 1000 lb of Coke Burnoff
SO_x[d]	1.86 lb SO_2/bbl fresh unit feed
CO[a]	Negligible
Hydrocarbons[a]	220 lb/1000 bbl fresh unit feed
NO_x[a]	7 lb/1000 bbl fresh unit feed
Tail Gas Treating Unit[e]	Assumes SO_2 emission from process is equivalent of unrecovered sulfur based on 99.8% total sulfur recover
Miscellaneous Sources[f]	0.37 lb hydrocarbons/bbl of capacity

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[a] Reference 1

[b] S_o = weight percent sulfur in fuel oil - taken to be 0.3% for Tables 13-16

S_f = sulfur concentration in fuel gas, taken to be 0.1 grains H_2S/1000 SCF for Tables 13-16

[c] Federal New Source Performance Standards emission limit

[d] Estimated based on 0.3 wt % sulfur in coke

[e] Does not include SO_2 from combustion of fuel in tail gas unit process incinerators.

[f] Reference 20

TABLE 14
REFINERY EMISSIONS SUMMARY - GASOLINE REFINERY[a]
(lb/day)

Crude Oil Type[b]	Sour				Sweet			
Capacity (1000 B/Day)	200		100		200		100	
Fuel Type[c]	Fuel Oil	Fuel Gas	Fuel Oil	Fuel Gas	Fuel Oil	Fuel Gas	Fuel Oil	Fuel Gas
Particulate	8120-24900	1090-3870	4060-12500	545-1940	7550-23200	1010-3650	3780-11600	507-1820
SO_x[d]	81000-115000	65500-68500	40500-57400	32800-34200	78000-109000	63600-66300	39000-54700	31800-33200
Carbon Monoxide	1400-4200	920-2770	700-2100	460-1390	1300-3610	1090-2580	651-1810	546-1290
Hydrocarbons[e]	83000-85800	83200-86400	41500-42900	41600-43200	75300-77900	79800-86100	37700-39000	39800-43000
NO_x	16300-42300	14000-39800	8170-21200	7420-19900	12000-45300	14000-37200	6020-22600	6980-13600

[a]Includes emissions from FCCU catalyst regenerator
[b]See Section 3.1.1 for a description of sour and sweet crude oil
[c]Assumes reifnery burns all oil or all fuel gas. In practice, fuel usage will be a combination of oil and gas.
[d]SO_x values include SO_2 equivalent of sulfur not recovered by sulfur plant and 0.3% (wt) sulfur in FCCU catalyst coke.
[e]Includes miscellaneous hydrocarbon emissions from tankage, flares, etc. of 0.37 lb/BBL of total refinery capacity.

TABLE 15

REFINERY EMISSION SUMMARY - FUEL OIL REFINERY
(lb/day)

Crude Oil Type[a]	Sweet						Sour					
Capacity (1000 B/D)	200		100		30		200		100		30	
Emission	Fuel Oil	Fuel Gas	Fuel Oil	Fuel Gas	Fuel Oil	Fuel Gas	Fuel Oil	Fuel Gas	Fuel Oil	Fuel Gas	Fuel Oil	Fuel Gas
Particulates	3850-11500	517-1520	1930-5760	259-773	578-1730	78-232	3490-10500	470-1400	1730-5230	235-701	524-1570	71-210
SO_x[b]	9810-25800	2190-3870	4910-12900	1090-933	1470-3870	328-580	7870-22400	1230-2480	3930-11200	613-1240	1180-3360	184-872
CO	664-1990	432-1310	332-996	218-652	100-299	65-197	602-1810	395-1190	301-1800	198-596	90-271	59-179
Hydrocarbons[c]	74700-76000	74800-76200	37300-38000	37400-38100	11200-11400	11200-11400	74600-75800	74700-76000	37300-37900	33300-38000	11200-11400	11200-11400
NO_x	6640-19900	5930-17800	3320-9960	2970-8900	995-2990	890-2670	6020-18100	5380-16100	3010-9040	2690-8070	903-2710	807-2420

[a]See section 3.1.1 for a description of sour and sweet crude oil.
[b]Includes SO_2 equivalent of sulfur released in tail gas.
[c]Includes miscellaneous hydrocarbon emissions from tankage flares, etc. of 0.37 lb/bbl of capacity.

Source: Mittelhauser Corporation

the refinery uses all fuel oil or all fuel gas for process fuel. In practice, process fuel is a combination of oil and gas. For refineries of equal complexity using the same process fuel but differing capacities, the overall emissions will be related directly to the capacity. This is because the same amount of fuel is used per barrel of feed and only the overall plant capacity has changed. In the other case where capacities are equal but complexities differ, the less complex plant will have lower overall emissions due to the decreased number of process units, process heaters and boiler capacity.

In comparing the refineries of equal complexity and capacity but using different process fuels, the refinery using fuel gas will have, with the exception of NO_x, lower overall air emissions.

In the case of the fuel oil refinery (Table 17), the distillation and catalytic reforming units are again the major sources of air emissions for the same reasons as in the gasoline refinery. Due to the fuel oil refinery being overall less complex than the gasoline refinery, the overall air emissions from the fuel oil refinery are less even though the emission for the process units are equal per barrel of unit charge.

3.6.2 Wastewater Discharge

The volumes and characteristics of the wastewaters produced and discharged by petroleum refineries is dependent upon parameters such as the properties of the crude oil, types of processing units, final product mix, and method of treatment and disposal. Therefore, the characteristics of the wastewaters produced and discharged will reflect individual site conditions and a "typical" wastewater cannot be defined. The data presented in this section represent a review of various refinery wastewater data which have been applied to the example refineries detailed in this document.

TABLE 16

PROCESS UNIT EMISSION SUMMARY - GASOLINE REFINERY
200,000 B/D, Sour Crude Oil (lb/Day)[a]

Fuel Used	Fuel Oil					Fuel Gas				
Process Unit	Particulates	SO_x	CO	Hydrocarbons	NO_x	Particulates	SO_x	CO	Hydrocarbons	NO_x
Atm.Distill.	2060-3060	4280-6160	340-540	340-540	3400-5400	276-412	370-554	234-350	400-598	3160-4740
Vac.Distill.	736-888	1520-1850	128-152	128-152	1280-1520	96-120	133-160	84-102	144-174	1140-1380
Delayed Cok.	1280-2000	2640-4160	220-344	220-344	2200-3440	172-268	230-360	146-228	248-388	1980-3080
Fluid Cat. Cracking	281-512	594-1060	50-89	50-89	500-890	40-73	51-96	32-59	56-102	439-822
Naphtha Cat. Reforming	1307-2300	2730-4830	226-396	226-396	2260-3960	174-309	235-416	150-265	253-451	2020-3570
Hydrocracking	807-3631	1690-7519	143-624	143-624	1430-6240	110-488	147-655	92-414	158-708	1260-5670
Naphtha Hydrotreating	130-453	272-762	11-79	11-79	110-790	23-62	33-83	23-57	34-91	277-713
Distillate Hydrotreating	273-353	535-655	46-56	46-56	460-560	33-41	465-569	30-36	49-59	400-490
Gas Oil Hydrotreating	333-495	690-957	56-86	56-86	560-860	45-65	60-88	38-55	65-96	515-749
Resid. Hydrotreating	392-480	812-920	68-84	68-84	680-840	53-63	71-84	44-53	76-92	604-716
Coker Naphtha Hydrotreating	15-52	31-110	3-9	3-9	30-90	3-7	4-10	3-6	4-10	32-82
HVV Gasoline Hydrotreating	35-123	74-262	6-22	6-22	60-220	6-17	9-23	6-14	9-25	75-194
HVY Gasoline Cat.Reforming	1590-2800	4290-5880	275-482	275-482	2750-4820	212-376	286-501	183-323	308-549	2460-4350
Isomerization	160-440	345-848	28-75	28-75	280-750	23-58	30-78	19-49	3385	259-669
Alkylation	800-3880	1670-8070	138-676	138-676	1380-6760	114-530	152-710	97-450	164-769	1310-6090
Hydrogren Production	105-109	254-310	25-21	18-22	423-517	16-20	24-22	15-17	26-22	189-229
Sulfur Recovery	100-123	210-255	17-21	17-21	170-210	13-17	18-22	12-14	21-25	154-188
Tail Gas Treating[b]	226-818	3190-4420	39-142	39-142	390-1420	30-110	2760-2870	26-93	44-159	348-1260
FCCU Catalyst Regn.&CO Boiler[c]	0-613	1-1380	0	7620	2343	0-	61400	0	7620	2340
Miscellaneous	-	-	-	74000[d]	-	-	-	-	74000[d]	-
TOTAL	10638-22930	87207-110602	1815-3902	83432-85518	20706-41630	1439-3646	66578-68691	1232-2635	83747-86027	18953-37291

[a]Ranges are based on range of fuel requirements. See Section 3.1.1 for a description of sour and sweet crude oil.
[b]Includes SO_2 equivalent of sulfur released in tail gas.
[c]Based on max. allowed emission listed in NSPS and assumed 0.3%(wt) sulfur in coke.
[d]Based on 0.37 lb hydrocarbon emission/BBL plant capacity.

Source: Mittelhauser Corporation

TABLE 17

PROCESS UNIT EMISSION SUMMARY - FUEL OIL REFINERY
200,000 B/D, 1.5% Sour Crude Oil (lb/Day)[a]

Fuel Used	Fuel Oil					Fuel Gas				
Process Unit	Particultes	SO_x	CO	Hydrocarbons	NO_x	Particulates	SO_x	CO	Hydrocarbons	NO_x
Atm.Distill.	2060-3060	4280-6160	340-540	340-540	3400-5400	276-412	370-554	234-350	400-598	3160-4740
Vac.Distill.	736-888	1520-1848	128-152	128-152	1280-1520	96-120	133-160	84-102	144-174	1140-1380
Naph.Cat. Reforming	1310-2300	2730-4830	226-396	226-396	2260-3960	174-309	235-416	150-265	253-451	2020-3572
Naphtha Hydrotreating	130-453	272-762	11-79	11-79	110-790	23-62	33-83	23-57	34-91	277-713
Distillate Hydrotreating	273-353	535-655	46-56	46-56	460-560	33-41	465-569	30-36	49-59	400-490
Gas Oil Hydrotreating	303-450	627-870	51-78	51-78	510-780	41-59	55-80	35-50	59-87	468-681
Resid Hydrotreating	392-480	812-920	68-84	68-84	680-840	53-63	71-84	44-53	76-92	604-716
H_2 Production	105-109	254-310	25-21	18-22	423-517	16-20	22-26	15-17	22-26	189-229
Sulfur Recovery	76-94	159-194	13-17	13-17	130-170	10-12	13-17	9-11	14-18	13-15
Tail Gas Treating[b]	170-616	2150-3070	30-107	30-107	300-1070	23-83	1820-1920	20-70	33-120	262-949
Miscellaneous	-	-	-	74000[c]	-	-	-	-	74000	-
TOTAL	5555-8803	13339-19819	1260-2136	75270-76139	12793-21627	745-1181	3217-3909	642-961	75088-75716	8533-13485

[a]Ranges are based on range of fuel requirements. See Section 3.1.1 for a description of sour and sweet crude oil.
[b]Includes SO_2 released with tail gas.
[c]Based on 0.37 lb Hydrocarbon/BBL of plant capacity.

A general list of the sources of refinery wastewater is shown on Table 18. Process wastewaters are generated by the processing units and are the sulfide and ammonia containing water streams (sour water) produced through direct contacting of steam or water with the petroleum fractions. The wastewater from the cooling and boiler systems are due to the make-up water treating systems and the boiler and cooling water blowdown streams which are generated to maintain system water quality. Wastewaters from tankage are generated by condensate which collects in the tanks, water entrained with the crude oil, and tank washwaters. Miscellaneous sources include ballast water from seagoing vessels, oily storm runoff, and effluents from cleaning of tank cars, tank trucks, and drums.

The volumes of wastewater produced by each source is dependent upon overall refinery configuration and use of in-plant source control measures. Inland refineries, for example, will not have ballast water to treat and a highly complex refinery will generate more process wastewater than a more simple refinery. Cooling system blowdown can be minimized by employing blowdown treatment and recycle systems. Close attention to unit operation can minimize the process wastewater produced. Therefore, the volumes of wastewater generated will be specific to a given refinery and dependent upon the general operating conditions.

The water pollutants found in refinery wastewaters include Biochemical Oxygen Demand (BOD_5), Chemical Oxygen Demand (COD), oil, total suspended solids (TSS), Ammonia (NH_3), phenol, hydrogen sulfide (H_2S), trace organics, and some heavy metals.* Table 19 shows the major sources of each of these pollutants. Process wastewaters contribute a portion of virtually all pollutants while other sources have more specific pollutant discharges.

The estimated total wastewater discharges for the example gasoline and fuel oil refineries are shown in Table 20. The data assume that similar refineries practice the same degree of in-plant

*See glossary for definition of terms.

TABLE 18

WASTEWATER SOURCES

Source	Wastewater Description
Process Units	Sour Condensates
Cooling Tower	Cooling Tower Blowdown, Effluents from Make-up Water Treating
Boilers	Boiler Blowdown and Feedwater Treatment Effluents
Tank Farm	Tank Drainage and Cleaning Effluents
Miscellaneous Oily Wastewaters	Ballast Water, Tank Car Washing Effluents, Storm Water Runoff, etc.

Source: Mittelhauser Corporation

TABLE 19

POLLUTANT SOURCES

Pollutant	Source
BOD_5	Process Wastewater Cooling Tower Blowdown (if hydrocarbons leak into cooling water system) Ballast Water Tank Flow Drainage and Runoff
COD	Process Wastewater Cooling Tower Blowdown (if hydrocarbons leak into cooling water system) Ballast Water Tank Flow Drainage and Runoff
Oil	Process Wastewater Cooling Tower Blowdown (if hydrocarbons leak into cooling water system) Ballast Water Tank Flow Drainage and Runoff
Total Suspended Solids	Process Wastewater Cooling Tower Blowdown Ballast Water Tank Flow Drainage and Runoff
Phenol	Process Wastewater (particularly from Fluid Catalytic Cracking Unit)
NH_3, H_2S, trace organics	Process Wastewater
Heavy Metals	Process Wastewaters, Tankage Wastewaters Discharges Cooling Tower Blowdown (if chromate type cooling water treatment chemicals are used)

Source: Mittelhauser Corporation

TABLE 20

ESTIMATED TOTAL WASTEWATER VOLUMES GENERATED FROM EXAMPLE GASOLINE REFINERIES

Type of Crude Oil*	Sour				Sweet			
	200		100		200		100	
Capacity (1000 B/Day)	GPM	MGD	GPM	MGD	GPM	MGD	GPM	MGD
Wastewater								
Process	1510	2.18	755	1.09	1410	2.02	703	1.01
Tank Farm	110	0.16	55	0.08	110	0.16	55	0.08
Boiler & Cooling Towers	1340	1.93	670	0.97	1260	1.82	630	0.91
Runoff, Ballast, Misc.	1940	2.79	970	1.40	1940	2.79	970	1.40
Sanitary	20	0.02	10	0.01	12	0.02	9	0.01
Total 4920	4920	7.08	2460	3.55	4733	6.81	2368	3.41

ESTIMATED TOTAL WASTEWATER VOLUMES GENERATED FROM EXAMPLE FUEL OIL REFINERIES

Type of Crude Oil*	Sour						Sweet					
Capacity (1000 B/Day)	200		100		30		200		100		30	
Wastewater	GPM	MGD	GPM	MGD	GPM	MGD	GPM	MGD	GPM	MGD	GPM	MGD
Process	973	1.40	487	0.70	146	0.21	745	1.07	373	0.54	112	0.16
Tank Farm	60	0.09	30	0.05	10	0.01	60	0.09	30	0.05	10	0.01
Boiler & Cooling Towers	782	1.13	391	0.51	117	0.17	719	1.04	360	0.52	108	0.16
Runoff, Ballast, Misc.	970	1.40	485	0.70	146	0.21	970	1.40	485	0.70	146	0.21
Sanitary	9	0.01	6	0.01	2	0.003	8	0.01	5	0.010	2	0.002
Total	2794	4.03	1369	2.07	421	0.603	2502	3.61	1253	1.820	378	0.542

*See Section 3.1.1 for discussion of sour and sweet crude oil.

source control, blowdown handling, etc. It must be realized that these are estimates only and should not be taken as generalized values applicable to all refineries. The data, however, indicate a realistic evaluation of the wastewaters produced by refineries of the configurations outlined in this document.

As shown in the tables, wastewater discharges are a function of refinery capacity, complexity, and product mix. Refineries processing the same crude oil (equal complexity) and having the same product mix but having different capacities will have wastewater discharges proportional to the difference. This is because the refineries have identical configurations, thus the wastewater produced per barrel of capacity will be the same. However, due to the overall capacity difference, the plant with lower capacity will generate proportionally less wastewater.

In comparing gasoline refineries of equal capacity but processing different crude oils (different complexity),* there is notable difference in the volume of the process, boiler and cooling water waste streams. This is because the sweet crude oil plant (less complex) has less process units and lower steam and cooling requirements.** Thus, less wastewater is generated by the less complex plant.

A somewhat different situation occurs when comparing the other wastewater streams. Since equal capacity sour and sweet crude oil gasoline refineries will have similar requirements for tankage, ballast water handling and tank and tank car washing, wastewaters from these sources will be about the same for each refinery. The same type of analysis applies to the fuel oil refineries processing sour and sweet crude oil.

Comparison of the process water tankage, storm runoff, ballast water and miscellaneous wastewater volumes generated by the gasoline and fuel oil refineries, shows that the fuel oil refinery will have

*See Section 3.2 for a discussion of plant complexity.
**See Section 3.3 for a discussion of steam and cooling water requirements.

less volume, even though the plants may have similar capacities. This is because the complexities and product mixes are vastly different and tankage and other such requirements for the fuel oil refinery are not as extensive, and therefore overall less wastewater will be generated.

Tables 21 and 22 give the breakdown of process wastewaters by unit from example gasoline and fuel oil refineries and the concentration of pollutants from each source prior to introduction to any wastewater treating unit. The process unit contributing the largest pollutant load is the delayed coking unit. The wastewater discharged is primarily the excess cutting water used to remove the coke from the coke drums.* Other process units producing significant process wastewaters are the distillation units, and the fluid catalytic and hydrocracking units. It should be noted that the process units contributing the largest pollutant load are those involved with fractionation or cracking of the charge stock.

Of the pollutants present in the process wastewaters, the most highly concentrated are the sulfide and ammonia. If present in sufficiently high amounts, sulfide and ammonia can cause reduced performance of the wastewater treatment unit. For this reason, wastewaters from process units are typically combined and passed through the sour water stripping unit before being discharged to the wastewater treating unit.** These units will remove 98% or more sulfide and 92% or more of the ammonia, which greatly reduces the pollutant loading on the wastewater treating unit. Thus, the actual concentration of sulfide and ammonia in the wastewater treating unit influent is much lower than that discharged from the process units.

In comparing the process wastewater composition of the gasoline and fuel oil refineries, the most notable difference is that the fuel oil refinery has much lower concentrations of BOD_5 and phenol. This is

*See Section 2.7 for a description of the delayed coking unit.
**See Section 2.16 for a description of the sour water stripping unit.

TABLE 21

ESTIMATED UNTREATED WASTEWATER COMPOSITIONS FROM A GASOLINE REFINERY[a]

Process Unit	Wastewater GPM	Wastewater Pollutants (PPM) BOD$_5$	COD	Suspended Solids	Oil	Phenols	Sulfide[b]	Ammonia[b]	Cr
Atmos. Distillation	415	314	471	100	200	20	3,000	2,300	0
Vacuum Distillation	210	590	585	150	300	100	200	150	0
Fluid Catalytic Cracking	120	960	1440	100	200	400	7,000	5,300	0
Hydrocracking	85	140	210	50	100	nil	60,000	45,000	0
Naphtha Hydrotreating	40	252	378	80	180	nil	2,000	1,500	0
Distillate Hydrotreating	35	112	168	40	80	nil	10,000	7,500	0
Gas Oil Hydrotreating	70	70	105	30	50	nil	20,000	15,000	0
Residuum Hydrotreating	100	70	100	30	50	nil	70,000	53,000	0
Coker Gasoline Hydrotreating	5	280	420	100	200	nil	2,000	1,500	0
FCCU Gasoline Hydrotreating	10	280	420	100	200	nil	2,000	1,500	0
Naphtha Reforming	5	210	315	50	150	nil	nil	nil	0
Cracked Gasoline Reforming	5	210	315	50	150	nil	nil	nil	0
Delayed Coking	230	1580	2370	300	400	600	9,000	6,800	0
C_5/C_6 Isomerization	5	280	420	80	200	nil	nil	nil	0
HF Alkylation	20	210	315	50	150	nil	nil	nil	0
Gasoline Sweetening	5	244	366	100	150	20	150	100	0
Light Ends Recovery[c]	150	314	471	100	200	20	3,000	2,300	0
Sulfur Recovery[d]	0	0	0	0	0	00	0	0	0
Hydrogen Production	0	0	0	0	0	0	0	0	0
TOTAL PROCESS WASTEWATER[e]	1510	550	825	125	210	145	12,300	8,300	0
Other Wastewaters									
Crude Oil and Other Tanks	110	560	840	300	400	0	0	0	0
Runoff, Ballast Water, Misc.	1940	420	630	300	300	0	0	0	0
Boiler Blowdown, Cooling Tower Blowdown, etc.	1340	0	0	0	0	0	0	0	2-10[f]

[a] 200,000 B/Day, Sour. Data show compositions prior to any wastewater treating unit. See Table 18 for treated wastewater analysis. See Section 3.1.1 for a description of sour and sweet crude oil.

[b] Sulfides as H_2S, ammonia as NH_3 [c] Includes amine units [d] Including tail gas unit

[e] lb/day = PPM x GPM x 0.012

[f] Depends upon volume of cooling tower blowdown, if chromium based, cooling water chemicals are used, and if blowdown pretreatment is practiced.

Source: Mittelhauser Corporation

TABLE 22

ESTIMATED UNTREATED WASTEWATER COMPOSITIONS FROM A FUEL OIL REFINERY[a]

Process Unit	Wastewater GPM	Wastewater Pollutants (PPM) BOD$_5$	COD	Suspended Solids	Oil	Phenol	Sulfide[b]	Ammonia[b]	C_r
Atmospheric Distillation	415	314	471	100	200	20	3000	2300	0
Vacuum Distillation	210	590	885	150	300	100	200	150	0
Naphtha Hydrotreating	40	252	378	80	180	0	2000	1500	0
Distillate Hydrotreating	35	112	168	40	80	0	10000	7500	0
Gas Oil Hydrotreating	63	70	105	30	50	0	20000	15000	0
Residuum Hydrotreating	100	70	105	30	50	0	70000	53000	0
Naphtha Reforming	5	210	315	50	150	0	0	0	0
Gasoline Sweetening	5	244	366	100	150	20	150	100	0
Light Ends Recovery Unit[c]	100	314	471	100	200	20	3000	2300	0
Sulfur Recovery[d]	0	0	0	0	0	0	0	0	0
Hydrogen Production	0	0	0	0	0	0	0	0	0
TOTAL PROCESS WASTEWATER[e]	973	322	483	96	191	32	10515	8016	0
Other Wastewaters									
Crude Oil and Other Tankage	60	560	840	300	400	0	0	0	0
Runoff, Ballast Water, Misc.	970	420	630	300	300	0	0	0	0
Boiler Blowdown, Cooling Tower Blowdown, etc.	982	0	0	0	0	0	0	0	2-10[f]

[a]200,000 B/Day, Sour. Data show compositions prior to any wastewater treatment unit. See Table 18 for treated wastewater analysis. See Section 3.1.1 for a description of sour and sweet crude oil.

[b]Sulfide as H_2S, Ammonia as NH_3

[c]Includes amine units

[d]Includes tail gas units

[e]lb/day = PPM x GPM x 0.012

[f]Depends upon volume of cooling tower blowdown, if chromium cooling water treatment chemicals are used, and if any blowdown treatment is practiced.

Source: Mittelhauser Corporation

because the fluid catalytic cracking unit and the delayed coking unit which are the major contributors of these pollutants are not present in the fuel oil refinery configuration. However, concentrations of other contaminants such as ammonia and oil are similar between the two refineries. This is because the process units, such as the distillation units which generate the majority of these pollutants are present in both refineries.

Wastewaters discharged to the wastewater treating unit include stripped process wastewater, oily storm runoff, tank drainage and cooling tower blowdown. Depending upon site conditions and discharge regulations, it may be possible to minimize the wastewater volume to be treated by handling boiler blowdown and ballast water separately.

Table 23 shows the estimated amounts of regulated pollutants discharged from the wastewater treatment unit for two example refineries. These values assume that each plant has a wastewater treatment unit configuration as shown in Figure 23, Section 2.17. As shown, the more complex, gasoline refinery discharges a greater overall pollutant load than the less complex fuel oil refinery. This is due primarily to the greater number of wastewater sources in the gasoline refinery and the fact that the wastewater treatment units for each plant have similar efficiencies. However, since the Federal discharge regulations allow for differences in complexity, both of the effluents shown in this table are within the prescribed Federal discharge limits.*

In reviewing the amount of individual pollutants discharged with the final effluents from each plant, the major difference occurs in the phenol discharges. This again is due to the fact that the fuel oil refinery does not have cracking or coking units which are the main producers of phenolic wastewaters. Since the wastewater treatment units' efficiencies are equal, it would be expected that the gasoline refinery would have a greater phenol discharge.

*See Section 4.0 for a complete discussion of discharge regulations.

TABLE 23

ESTIMATED CHARACTERISTICS OF FINAL EFFLUENTS FROM EXAMPLE GASOLINE AND FUEL OIL REFINERIES[a,b]

	Gasoline Refinery		Fuel Oil Refinery	
Wastewater Treatment Unit Effluent Flow (MGD)[c]	6.25		3.45	
Wastewater Parameter	lb/day	lb/1000 barrels crude oil	lb/day	lb/1000 barrels crude oil
Biological Oxygen Demand (BOD_5)	714	3.6	341	1.7
Chemical Oxygen Demand (COD)	5360	26.8	2560	12.8
Total Suspended Solids	781	3.9	431	2.1
Oil and Grease	111	0.56	55	0.3
Phenol	6.7	0.033	0.83	0.004
Sulfide	3.5	0.02	1.7	0.009
Ammonia (as N)	152	0.76	85	0.43
Total Chromium (as Cr)[d]	19	0.094	7.4	0.05
PH (pH units)	6-9		6-9	

[a]Both refineries are processing 200,000 B/D of sour crude oil

[b]Assumes wastewater treatment unit configuration shown in Figure 23, Section 2.17.

[c]MGD = Million gallons per day

[d]Hexavalent chromium not listed separately due to insufficient data. Assumes 10 ppm total chromium in cooling tower blowdown.

Of the other pollutants listed, the fuel oil refinery discharges about 40 to 50% of the pollutants discharged by the gasoline refinery. This is also expected as the fuel oil refinery is less complex and generates, overall, less wastewater. However, should these plants use different wastewater treatment schemes or have different process configurations, the final effluent characteristics may change significantly from those shown here and the actual final effluent from a given refinery must be evaluated on an individual basis.

In terms of priority or toxic pollutants, studies have detected a number of these compounds in refinery wastewaters.[16] The actual compounds present and their concentrations vary greatly among refineries and their occurrence cannot be generalized. The recently published EPA development document for the refining industry lists the results of a sampling and analysis program for the priority pollutants.[16]**

From this and other studies it was found that the wastewater treating units, similar to that described in this document, will remove the "organic priority pollutants to 'low' levels (i.e., 10-100 micrograms per liter)."[16] At present, little is known about the occurrence and treatability of organic toxic (priority) pollutants in refinery wastewaters. It is currently felt that if the proposed Best Available Control Technology (BACT) Discharge Limits for phenol are achieved, other toxic (priority) organic pollutants will also be controlled.[18] It must be realized, however, that the BACT limitations for chromium and phenol are at this time only proposed, and actual limits have not yet been established. As more data becomes available, however, this situation may change and the priority pollutants in general or specific priority pollutants may have separate discharge limitations.

Metals such as chromium, zinc, copper, and arsenic are also toxic pollutants and may be present in refinery wastewaters. These metals are added through chemicals used in the refining process and

*For discussion of Priority Pollutants Regulations, see Section 4.0.

brought in with the crude oil. The wastewater treating unit typically removes most of these metals and special treatment for their removal is not required.[16] Chromium may be an exception, in that cooling water treating chemicals may contain significant chromium concentrations. If the wastewater treating unit will not adequately remove chromium, then segregated treatment of cooling tower blowdown may be employed, but this is dependent upon the individual refinery. Like the organic priority pollutants, it is currently felt if chromium is controlled to the proposed BACT standards, other toxic metals will also be controlled.[18]

The wastewater treatment system outlined in this document shows the final effluent being discharged to a receiving stream. However, smaller refineries may find it more economical to pretreat the wastewater and then discharge the effluent to a publicly owned treatment works (POTW). It has been shown that properly pretreated refinery wastewater can be effectively handled by a POTW, in terms of both conventional (BOD, COD, etc.) and priority pollutants.[16] The current pretreatment regulations require a refinery treat its wastewaters to the same quality levels as if it were discharging to a receiving stream. The choice of discharging to a POTW or a receiving stream is dependent upon individual site considerations.

3.6.3 Solid Wastes

A petroleum refinery generates a wide variety of solid wastes some of which may contain materials currently listed by the EPA as toxic substances, particularly heavy metals such as chromium and zinc. While the total combined treated wastewater effluent from modern refineries is of relatively uniform composition and has been extensively quantified, the nature and quantity of solid wastes generated by refineries are highly variable and still the subject of investigation.

Generally, refinery solid wastes fall into two main groups: those that are intermittently generated and those that are generated continuously. Intermittent wastes are generally those that result from cleaning within the process areas and off-site facilities of the refinery. The following are typical intermittent waste streams:

- process vessel sludges, corrosion products, and other deposits generally removed during process unit maintenance
- storage tank sediments
- product treatment wastes, such as spent filter clay and spent catalysts from certain process units.

Continuous wastes are those requiring disposal at less than two week intervals and can be further broken down into two groups: process unit wastes and wastewater treatment wastes.[1] Major process unit wastes include:

- coker wastes, such as coke fines from delayed or fluidized cokers, and spilled coke from unloading facilities.
- neutralized sludge from HF alkylation units.
- spent catalysts and catalysts fines from the fluid catalystic cracking units.

Wastewater treatment wastes can include:

- waste biological sludges from activated sludge units
- sediment from API separators.

Table 24 is a detailed listing of the sources and types of solid wastes generated by a refinery. The actual solid wastes generated by a refinery will depend upon the nature and operation of process units and the final product mix.

The spent process catalysts represent a special case of solid waste. While these catalysts will lose activity and must be taken out of service, they may not be simply discarded after use. Since they contain valuable metals, such as platinum, these materials

TABLE 24

PETROLEUM REFINERY SOLID WASTES
SOURCES AND CHARACTERISTICS

Type of Solid Waste	Generation Frequency*	Sources	Description	General Characteristics
Process Wastes		Crude Oil Desalter	Sediment	Sand, Grit, could be oily
	C/I	Fluid Catalytic Cracking Unit	Catalyst Fines/ Spent Catalyst	Catalyst particles, coke particles inert solids
	I	Other Catalytic Units	Spent Catalyst	Heavy metal catalyst particles, coke particles, inert solids
	C	Delayed Coking Unit	Petroleum Coke	Coke fines and coke spilled during handling
	C	HF Alkylation Unit	Neutron Bed HF Sludge	Calcium Fluoride solids, Bauxite, aluminum chloride sludge
	C	Gasoline Sweetening	Sulfide Residue	Insoluble sulfide sludge
	C	Slop Oil Treatment	Precoat Filter Solids	Diatomaceous earth solids, could be oil
	C	Other Filtering Operations	Precoat Filter Solids	Clay or diatomaceous earth filter cake
Effluent Treatment Wastes	C	API Separator	Bottom Sediment	Sand, grit. inert solids
	C	Air Flotation Unit	Scum or Froth Bottom Solids	Floatable Solids Settable solids (grit, etc.)
	C	Wastewater Sludge Processing Units	Wastewater Sludge	Biological Solids, Water
	I	Storm Water Sludge Bed	Sediment	Dirt, sand, grit, could be oily
Other Wastes	I	Crude Oil Storage Tanks	Sediment	Sand, dirt, inert solids, could be oily
	I	Other Storage Tanks	Sediment	Corrosion products could be oily
	I	Recirculating Cooling Water System	Tower Basin Sludge Solids from Blowdown Treatment	Corrosion productions, dirt, grift lime sludge (if lime softening is used)
	I	Once-through Cooling Water System	Solids from Water Treating	Lime, sludge (if lime softening is used) corrosion products
	C	Boiler Feedwater Treating	Solids from Water Treating	Lime solids (if lime softening is used) inert, settleable solids
	I	Unit Maintenance	Heat Exchanger Bundle Cleaning Sludge	Deposited Solids, corrosion products, scale
	I		Process Unit Solids	Deposited Solids within process units, corrosion products, scale, coke

* I = Intermittent
C = Continuous

Source: Reference 1

are frequently contain valuable metals, such as platinum, these materials may be sold to a reclaimer for reprocessing and recovery of the metals. This, however, is an economic decision.

The largest source of process catalyst is the fluid catalytic cracking unit. For an average 100,000 to 150,000 barrels per day refinery, as much as 120 tons of spent catalyst can be accumulated. Depending upon such factors as the quality of the spent material and the base material, the catalyst can be sold for use in other FCCUs, used in other plants who can use the catalyst, or, since it is essentially clay materials, landfilled.

Of the solids listed in Table 24, the lime sludge generated by boiler feedwater treating, and the wastewater treatment solids are the largest in volume. While the specific amounts vary with each refinery, these sources generally account for the largest share of the total solid wastes generated. The proportion of each will depend upon the water and wastewater characteristics and the method of boiler water treatment employed.

Factors affecting the composition and quantity of specific solid wastes are shown in Table 25. The factors are general and may not be of equal importance in all refineries. In addition, factors affecting the generation of one solid waste may affect the characteristics of other solid wastes. For example, process sludges are typically affected by process unit feedstock characteristics and unit operating conditions. In turn, the composition and quantity of wastewater treatment sludge generated is dependent on the characteristics of the wastewaters which is directly affected by the process unit operating conditions. A similar situation occurs in the cooling water system. The characteristics of the cooling tower sludge is dependent upon such factors as the make-up water quality and the effectiveness of the water treatment chemicals and process leaks. Since this cooling water is used in heat exchangers, some of the sludges generated through heat exchanger cleaning, will be directly affected by the quality of the cooling water. Therefore, the generation of any given solid waste is governed by a variety of interrelated factors and not only by the characteristics of the source.

TABLE 25

FACTORS AFFECTING THE COMPOSITION AND QUANTITY SPECIFIC SOLID WASTE STREAMS

Waste	Factors Affecting Composition and Quantity
Crude Oil Desalter Sediment	Type of crude, solids content of crude, type of desalting process
Fluid Catalytic Cracking Unit Catalyst Fines and Spent Catalyst	Catalytic composition Feed Composition and Rate Type of Process Process operating conditions Catalyst make-up rate Process metallurgy Number of cyclones Use of electrostatic precipitators
Spent Catalyst from Other Catalytic Processing Units	Catalyst Composition, Feedstocks Characteristics, Process Operating Conditions, Process Metallurgy
Petroleum Coke	Feed composition and Rate Type of process Process operating condition Process metallurgy Method of coke removal Method of handling and shipping
Neutralized HF Sludge	Composition of fresh HF acid Composition of lime Feedstock composition Process operating conditions HF alkylation process metallurgy Size of HF alkylation unit
Gasoline Sweetening	Type of sweetening process, process operating conditions, feedstock characteristics
Slop Oil Treatment Sludges	Amount of slop oil processed Characteristics of slop oil
Other Filtering Operations	Type of filter media, amount and type of material processed
Cooling Tower Basin Sludge	Makeup water composition Type and quantity of chemical treatments employed Metallurgy of cooling water system Nature of contaminants introduced by process leaks Blowdown rate Makeup water rate
Once-through Cooling Water System Sludge	Type and quantity of treatment employed Composition and quanitty of raw water Cooling system metallurgy Size and nature of process leaks Refinery size and complexity
Boiler Feedwater Treatment Sludges	Composition of raw water Degree of hardness removed Type of treatment Refinery size Boiler blowdown rates Percent condensate recovered and returned to boilers
Heat Exchanger Cleaning Sludge	Composition of shell and tubeside fluids Equipment metallurgy Effectiveness of desalter Refinery size and complexity Effectiveness of corrosion inhibitor systems
Process Unit Solids	Type of process, and operating conditions, frequency of maintenance

TABLE 25 (Contd)

API Separator Bottom Sludge	Composition and quantity of process wastewater Composition and quantity of spills and leaks Composition and quantities of blowdowns Refinery housekeeping Refinery size and age Segregation of refinery sewers
Air Flotation Unit Scum and Bottom Sludge	Same Factors as API separator sludge plus: Residence time Amount and time of flocculating chemical used Efficiency of API Separator
Wastewater Biological Sludge	Composition and quantity of wastewater treatment Type of biological treatment Efficiency of prior treatment units Operating conditions and practice Dewatering and/or treatment (filtration, digestion)
Storm Water Surge Pond Sediment	Plant housekeeping Amount of rain Amount of refinery area paved Segregation of surface drainage
Crude Oil Storage Tank Sediment	Type of crude oil Treatment given to crude oil prior to storage Slop oil processing method Refinery size Mixing, if any Storage time Degree, if any, of sludge emulsion breaking
Other Storage Tank Sediment	Type and quantity of chemical additives Plant and tank metallurgy Type of product treatment used Type of processes used in producing gasoline and/or other products Refinery size

Source: Reference 1.

Final disposal of the solid wastes presents a formidable problem and the actual disposal method depends heavily upon the characteristics of the waste and the disposal options available (i.e., proximity of approved landfills, etc.). Some solid wastes may contain materials listed as toxic, and this will have an effect upon the disposal option chosen.

The most widely employed method of disposing of refinery solids wastes is to remove the wastes to an approved landfill site either directly by the refinery or through an outside contractor. This applies typically to process solid wastes and those whose general characteristics are inert solids, sand and grit. Solid wastes from wastewater treating may also be landfilled, but other options such as landfarming and incineration may also be considered.

The major concern in the disposal of spent catalysts and cooling tower sludges is the presence of heavy metals such as chromium and zinc. These metals can be leached from the solids and, if the solids are disposed of improperly, can cause a hazardous situation. Therefore, any landfilling of spent catalysts must be done with care.

Process catalysts are collected and either sold for reclaiming or direct reuse or sent to disposal at an approved site. The option chosen is dependent upon the type and amount of catalyst, availability of a reclaimer to the refinery, and the availability of a disposal site. It should be recognized, however, that most process catalysts have long life-times (i.e., 1 or more years) and require infrequent disposal. The noted exception is FCCU catalyst.

Other wastes such as lime sludge from boiler feedwater treating, cooling tower sludge, and maintenance solids are also removed to approved landfills, either combined or separately, again depending upon their characteristics. A portion of the lime sludges may be mixed with spent hydrofluoric acid from the HF alkylation unit for neutralization of the spent acid before going to disposal.

3.7 NOISE EMISSIONS AND CONTROL

Refineries may have a significant number of noise sources associated with both construction and operation. Construction noise sources include construction vehicles, compressors and jackhammers. Operation noise sources include furnaces, compressors, motors, flares and other equipment. Both types of noise are of concern and the impact on the surrounding of each depends upon various factors. Table 26 lists noise levels of typical activities, which can be used to compare refinery noise levels.

3.7.1 Noise Levels and Characteristics

The loudness of an acoustic signal is measured in terms of its decibel (dB) level. The decibel scale is logarithmic rather than linear with 0 dB corresponding to the approximate threshold of hearing. When an acoustic signal is expressed in decibels the numerical dB value is referred to as a sound pressure level or SPL, the word "level" denoting that the decibel scale is being used. Because of the logarithmic nature of the dB scale, SPL values are not directly additive. For example, if chain saw A and chain saw B each produce a SPL of 70 dB at a given microphone when operated singly, then operating A and B simultaneously will produce a combined SPL of 73 dB and not 140 dB as might be expected. Similarly, 10 chain saws, each of which produced 70 dB when operated individually, when all are operating together would produce a sound pressure level of 70 + 10 = 80 dB. And going from 10 to 100 chain saws would only increase the noise level an additional 10 dB to a SPL of 90 dB. This rule for adding sound pressure levels can be summarized as "increasing the number of identical contributing sources by a factor of 10 corresponds to raising the SPL by 10 dB.[34]

In general, when a listener moves away from a source of noise, the magnitude of the noise level sensed by the listener is reduced. If the source of noise acts as a "point source," for example, a

TABLE 26

APPROXIMATE NOISE LEVELS OF TYPICAL ACTIVITIES

INDOOR NOISE LEVELS	DECIBELS	OUTDOOR NOISE LEVELS
	140	THRESHOLD OF PAIN
	130	Pneumatic riveter
Oxygen torch	120	
	110	Elevated Train
		Jet flyover at 1000 feet
Rock and roll band	100	
		Farm tractor Lawn mower at 3 feet
Boiler Room	90	Motorcycle at 25 feet
Food blender at 3 feet		
		Diesel truck, 40 mph at 50 feet
Garbage disposal at 3 feet	80	
		Lawn mower at 100 feet
Shouting voice at 6 feet	70	
		Car, 50 mph at 50 feet
Normal speech at 3 feet		
	60	Heavy traffic at 300 feet
Average business office	50	Refineries at 2000-5000 feet from center of site
Average residence		Bird calls
	40	
Library		
	30	
		Quiet rural area at night
Broadcasting studio		
	20	Rustling leaves
	10	
	0	THRESHOLD OF HEARING

Source: Reference 35

parked truck with its engine idling, the reduction in noise with distance follows the spherical spreading law, i.e., a six dB reduction in SPL with each doubling of the distance (-6 dB/DD). If the noise source acts as a "line source," a heavy and constant flow of traffic on a very long and straight roadway for example, the sound signal spreads cylindrically and only produces a 3 dB reduction with each doubling of distance from this "line source" (-3 dB/DD).[35]

3.7.2 Construction Noise Emissions

Construction activity can be a significant source of noise for noise related annoyance. Refinery construction can typically require 24 months or more to complete which means a significant time of exposure to area residents. Sources of construction noise include cranes, compressors, and impact and earthmoving equipment. Table 27 shows these and other sources of construction noise and their various noise levels. As indicated in this tabulation, typical individual noise levels are about 85 dBA* at 50 feet from the source. Assuming 10 such items of equipment to be operating concurrently during a typical construction phase, the noise level would be 95 dBA at 50 feet, 65 dBA at 1600 feet and 59 dBA at 3200 feet. These levels will vary with the type and amount of equipment being used at any given time and will vary over the life of the construction of the plant. Since construction noise is temporary and with only limited nighttime operation, the overall impact on the local community will not be severe and is generally not of the same concern as the 24 hour noise associated with refinery operation.

Control of construction noise can be obtained through thoughtful planning of construction activities and the use of mufflers, and other devices to reduce noise levels at the source. Such procedures as

*Decibels measured on the A weighted network. For further discussion of the A weighted network see "American Standard Specification for General-Purpose Sound Level Meters," Std. 4, American Standards Association, N.Y., N.Y. (1961).

TABLE 27

CONSTRUCTION EQUIPMENT NOISE LEVELS

	Typical dBA Level at 50 Ft
Earth Moving	
Loader	78
Back hoe	82
Grader	86
Truck	88
Materials Handling	
Concrete Mixer	82
Concrete Pump	82
Crane	82
Stationary	
Generator	77
Compressor	81
Impact Equipment	
Wrenches	85
Jack Hammer/Drill	89
Pile Driver	100

Source: Reference 35

proper scheduling of noisy construction activities, proper routing of heavy trucks and other vehicles to and from the construction site, and using extremely noisy equipment only when necessary are all possible noise control measures.

3.7.3 Operating Noise Emissions

Refineries may have a wide variety of significant noise generators, including furnaces and heaters, motors, compressors, cooling towers, steam exhausts, flares and other equipment. Each source has its own noise characteristics and the majority of noise sources are located at or near process units. Other areas such as tank farms, offices, and maintenance shops do not contribute significantly to the refinery noise levels.

Under the Occupation, Health and Safety Act (OSHA), workers may not be continuously exposed to more than 90 dBA for more than 8 hours/day. For each 5 dBA over 90 dBA and up to a maximum 115 dBA, the allowable continuous exposure time is reduced by 50%. In addition, workers may not be exposed to more than 115 dBA on a continuous basis or more than 140 dBA for any length of time. If these noise levels cannot be achieved through source control, ear protection must be provided and used. However, this is not considered on long term acceptable solutions.

Table 28 lists the major sources of noise in a refinery. As shown, the noise emissions are primarily associated with process equipment and generally noise levels in the process areas are 70-90 dBA at distances of three feet from the source. In areas where the 90 dBA OSHA limit is exceeded, noise emission can be reduced through the use of noise control devices, such as mufflers, silencers, and application of acoustical insulation and enclosures. Table 28 also shows possible methods of noise reduction for various pieces of equipment.

Outside of the process areas, refinery noise levels decrease significantly. Since most refinery layouts locate process units toward

TABLE 28

SOURCES OF NOISE, AND METHODS OF NOISE REDUCTION

Equipment	Source of Noise	Method and Noise Reduction
Heaters	Combustion at Burners	Silencers Seals around control rods
	Inspiration of Premix Air at Burners	Lagging[a] of premix jets
	Draft Fans	Intake silencer or acoustic plenum
	Ducts	Lagging
Motors	TEFC Cooling Air Fan	Intake Silencer/Unidrectional fan
	WP II Cooling System	Absorbent duct liners
	Mechanical and Electrical	Enclosure
Airfin Coolers	Fan	Decrease rpm (increasing pitch)/Tip and hub seals Increase number of blades[b]/Decrease static pressure drop[b]
	Motors	Quiet Motor/Slower Motor
	Fan Shroud	Streamline air flow/Stiffening and dampening (reducing vibration)
Compressors	Discharge Piping and Expansion Joint	Inline silencer and/or lagging
	Antisurge Bypass	Use quiet valves and enlarge and streamline piping[b] Lag valves and piping/Inline silencers
	Intake Piping and Suction Drum	Lagging
	Air Intake	Silencer
	Discharge to Air	Silencer
	Timing Gears (axial)	Enclosure (or constrained damping on case) Silencers on intake and discharge and lagging)
	Speed Changers	Enclosure (or constrained damping on case)
Engines	Exhaust	Silencer (muffler)
	Air Intake	Silencer
	Cooling Fan	Enclose intake or discharge of both/Use quieterfan
Miscellaneous	Turbine Steam Discharge	Silencer
	Air and Steam Vents	Silencer/Use quiet valve
	Eductors	Lagging
	Piping	Limit velocities/Avoid abrupt changes in size and direction Lagging
	Valves	Limit pressure drop and velocities/Limit mass flow Use constrant velocity or other quiet valve Divide pressure drop/Size adequately for total flow Size for control range
	Pumps	Motor noise control

[a]General team for various types of acoustical insulation, applied directly to noise source.
[b]Usually limited to replacemeent items or new facilities.

Source: Reference 35

the center of the site, the effect of noise on areas surrounding the refinery is minimized. For example a 1976 refinery noise impact assessment for Eastport, Maine[34] showed that areas near the proposed 250,000 B/Day refinery were predicted to have increases of 6 to 23 dBA at 8000 and 5000 feet respectively from the proposed center of the refinery. The noise assessment concluded that:

- Due to the current "prestine" nature of the area surrounding the proposed site, the refinery will have an impact on the area noise.
- How this impact will be viewed by the area residents cannot be projected.

As shown in the example, the exact impact of a refinery noise on a given area cannot be predicted. While area noise level increases may be predicted mathematically, each site will impact the noise environment differently depending upon such factors as background noise levels, topography of the land, size of the plant and equipment used. The impact on local residents will depend somewhat on the historic noise environment of the area and their overall feelings about the refinery being built in their area.

Therefore, the impact of a refinery on area noise levels will be site specific and dependent upon a number of factors. While refineries do have sources of noise, they are usually well controlled and the overall plant does not severely affect area noise levels. In many areas, existing refineries have residential areas, farms, and beaches located at or near the plant boundaries without any significant noise intrusion.

3.8 PHYSICAL APPEARANCE

The physical appearance of a refinery will depend upon such factors as the types of process units employed, product mix, topography of the land, and geographical location. For example, refineries with a large capacity for product separation will have a large number of distillation columns. A substantial product mix will require a large area for tankage, and a coastal location will have facilities to accommodate tankers.

Figures 34 through 37 show the physical appearance of four refineries of different capacities. Figure 34 is a 350,000 B/D coastal refinery. This plant has a large area of tankage and a number of areas where process units are located. In comparison, Figure 35 shows a 120,000 B/D coastal refinery. This facility has the process units located in essentially one area. The tankage, while extensive, is also located in a cluster, rather than being spread out as in Figure 34.

Two inland refineries are shown in Figures 36 and 37. Figure 36 is a 200,000 B/D plant and Figure 37 shows a 30,000 B/D facility. These plants, like the 120,000 B/D coastal facility, have the process units located in a central area, and the tankage and other support facilities are located around the process area.

Due to the nature of refinery equipment, a number of process units and support facilities are readily recognized. These have been tagged on Figures 35, 36 and 37 and are detailed as follows:

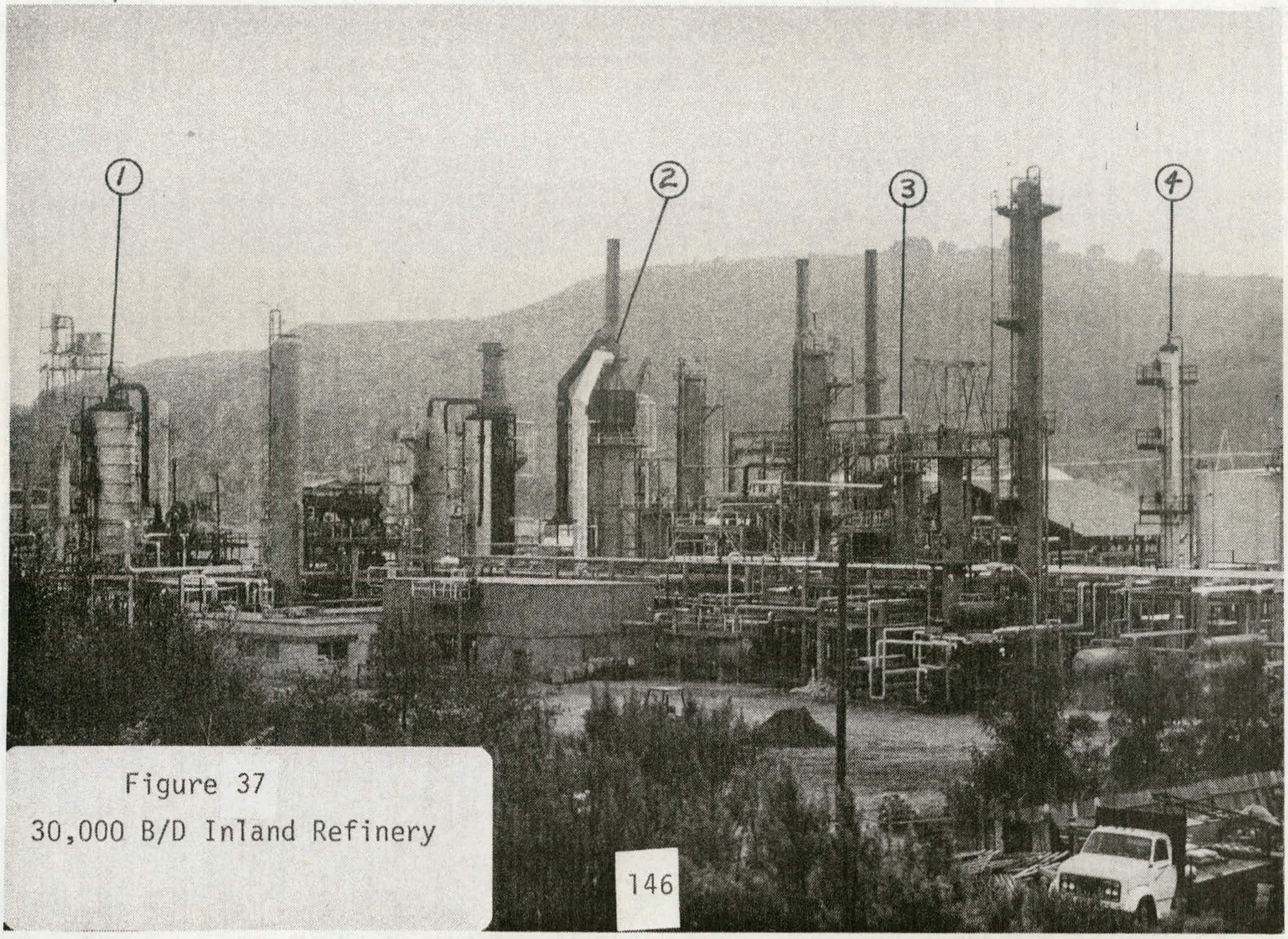


Figure 37
30,000 B/D Inland Refinery

Figure 35
120,000 B/D Coastal Refinery

Figure 34
350,00 B/D Coastal Refinery

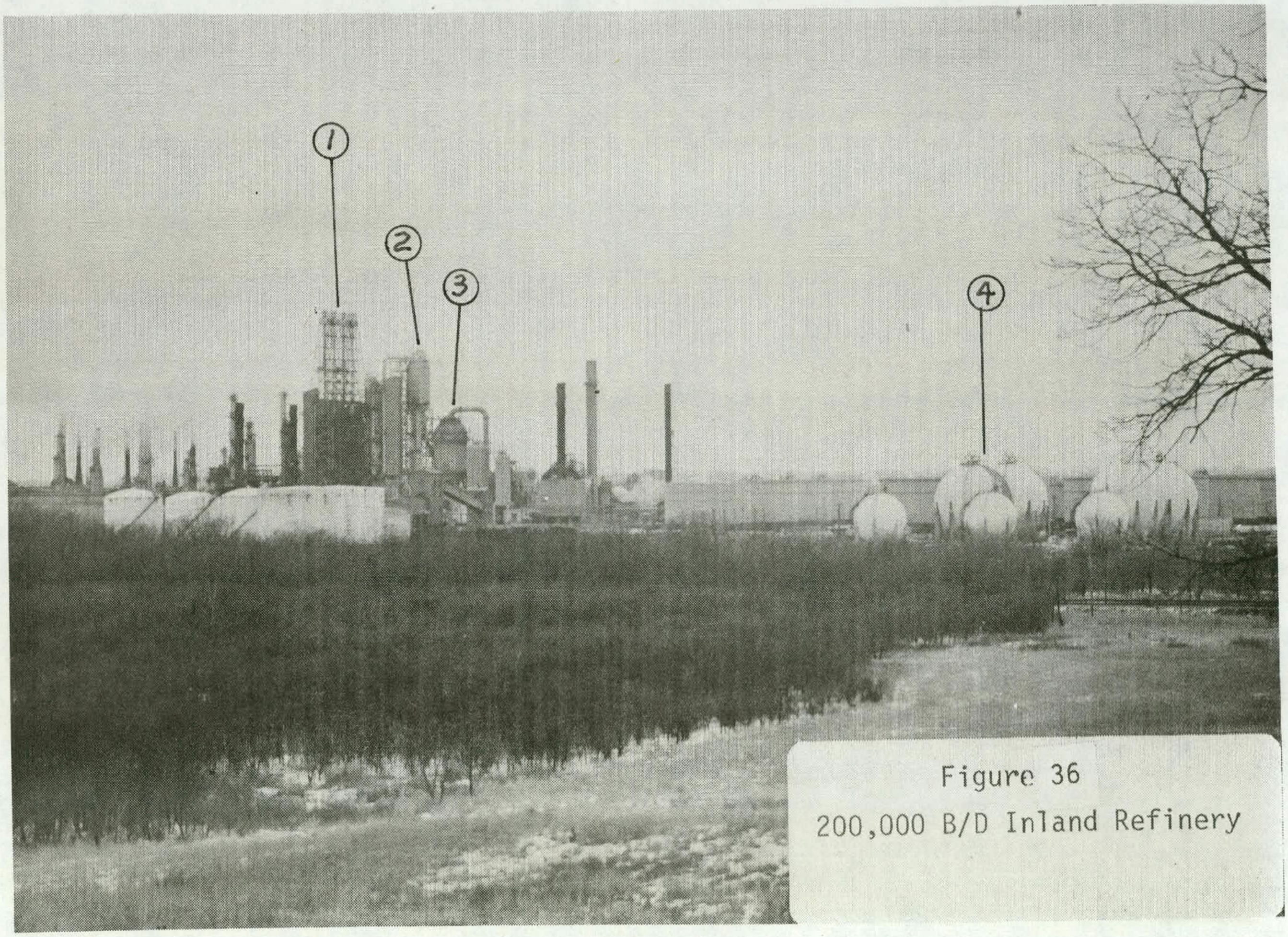


Figure 36
200,000 B/D Inland Refinery

TAG NUMBER

Figure	1	2	3	4
35	Floating Roof Tank	Tanker Loading Facilities	Distillation Columns	
36	Coke Drum	Catalytic Cracking Unit Reactor	Catalytic Cracking Unit Catalyst Regenerator	Gas Spheres
37	Crude Oil Distilla-tion Column	Crude Oil Distillation Column Feed Heater	Catalytic Reforming Unit	Acid Gas Treating Unit

3.9 SOCIO-ECONOMIC IMPACT ANALYSIS

3.9.1 Introduction

This section of the workbook outlines the process of community management and control of the impacts resulting from the construction and operation of a refinery. The community or areas of concern and methods for analysis of those elements presented here are generally applicable to all communities. However, it must be understood that individual communities will have specific needs and goals, and that actual elements considered and methods of analysis may vary widely between sites.

The various areas that are affected by the construction and operation of a refinery are highly inter-related. An increase, for example, of population, can cause a need for increases in the services area. Therefore, in order to describe the areas of concern, the methods for their analyses, and their inter-relationships, this section is organized as follows:

- 3.9.2 General impacts and considerations caused by refinery construction and operation
- 3.9.3 Description of socio-economic impact assessment procedure
- 3.9.4 Methods for analysis of the community environment
- 3.9.5 Techniques for management of the projected impacts.

3.9.1.1 The Relationship between Impact Assessment and Planning

Since many impact assessments have taken some rigidly defined action and then examined environmental impacts without allowing the results of the assessment process to modify the proposed action, the planner/local officials must assure that the characteristics of a refinery be allowed to evolve in the course of an interaction planning process. This process begins with a relatively broad range of alternatives in the early stages of the planning process, which are narrowed as impacts are given increasingly detailed scrutiny towards the final stages in the decision process. In this kind of process, impact assessment is embedded in the planning process and is constantly developing information that results in project modification or revision which must then be reassessed and so on. Independent of a planning process, impact assessment can be a sterile exercise that has no relation to the actual political and economic negotiations by which actions are taken and change occurs.

There are two implications of the above discussion. First, impact assessment is an integral part of the planning process. Planning cannot occur without methods that allow the future implication of different actions to be foreseen. Second, impact assessment must take place in a planning process if it is to be of any operational significance. Thus, there is an interdependent relationship between the planning process and impact assessment, with each requiring the other if it is to be appropriately carried out.

In any project, there are different planning needs correlated with the various stages of one project. These are typically defined as long-term alternative futures, site specific planning and monitor and mitigation planning.[37]

Long Term Alternative Futures Planning

This would include much of what is referred to as general planning along with some land use planning and economic development planning. The analysis is usually focused on a period 5 to 25 years in the future and the emphasis is on establishing the broad sets of alternatives that face an area. Future development possibilities would be analyzed, although the level of detail for many of the proposed developments (i.e., refinery complex) would not be significant. The impact assessment techniques appropriate to these studies should produce only estimates of the order of magnitude of impacts.

Site-Specific Planning

This refers to the class of planning problems where a proposed refinery has been defined in detail and where an intensive investigation of its implications is being made. This kind of planning and assessment problem is usually focused on a period from one to ten years in the future. The term site-specific is used to indicate that the level of project definition has progressed to the point of defining a site, a construction and operation schedule, materials requirements, etc. The assessments required for this kind of problem may be of the large, encyclopedic variety associated with many recent energy development proposals, or they may be more limited analyses intended to examine the implications of smaller projects. (In this workbook we are concerned only with this type of planning/impact assessment procedure.)

Monitoring and Mitigation Planning

This category of planning refers to the continuing need for planning and assessment after work on a project has begun. By this time the physical planning component will have increased in significance relative to impact assessment activities, but many of the same assessment tools will continue to be used. Even more important, however, the framework of cause and effect relationships at the heart of the assessment process continues to be the basis for understanding what is happening in response to the proposed refinery, e.g., a shortage of private capital may preclude an expansion in service sector employment which will reduce in-migration which will slow population growth which will diminish the need for increased wastewater treatment capacity.

Each of these three types of planning and assessment activities has its own methodological requirements. Therefore, due to the emphasis in this workbook on the socioeconomic impact induced by the construction and operation of a refinery, the evaluation and assessment methodology for site-specific planning will be presented. Particulate attention to the mitigation mechanisms available to alleviate and/or manage the impacts precipitated by the development will be addressed even though this is included in a different planning category.

3.9.2 General Impacts and Considerations Caused by Refinery Construction and Operation

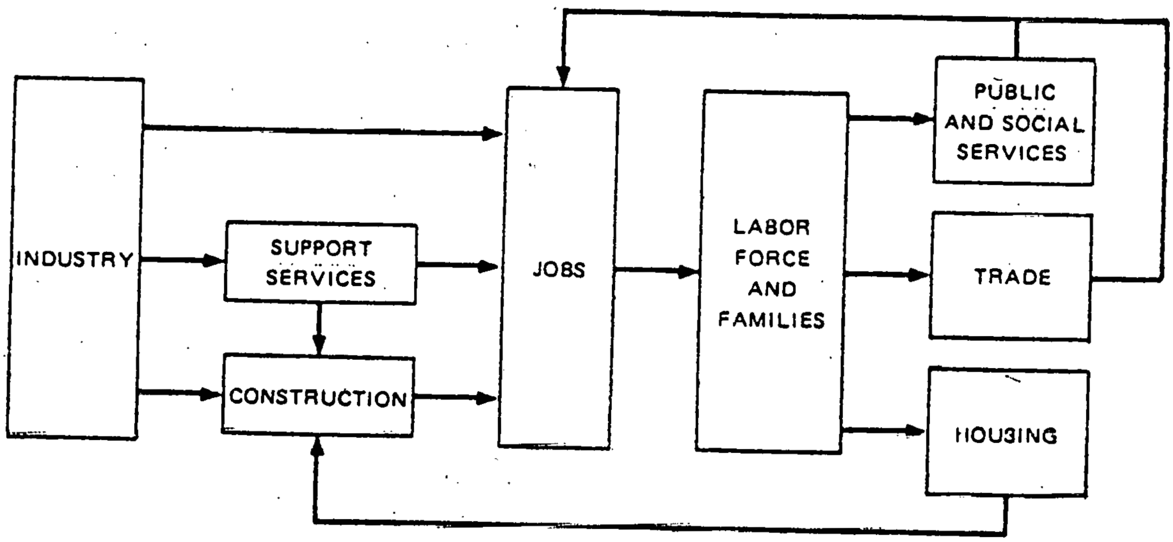
The construction and operation of an oil refinery will almost invariably cause changes in a community. The presence of the plant causes impacts in such areas as the need for support services, jobs, social services, of housing. The status and nature of the existing community prior to construction will determine which areas will be affected and the extent of the impact. Figure 38 shows how community growth is generally affected by the presence of an industrial facility (in this use, a refinery).

The construction and operation of the refinery will result in new jobs in the region. The refinery will generate increased business for supplying and support industries (e.g., construction materials, transportation facilities), and this activity will also generate increased employment. Depending on whether the increased employment opportunities are filled by local residents or by newcomers, the plant activities can cause a population influx in the community. The increased income generated by the plant and increased population will result in heightened demand for publicly and privately provided goods and services such as schools, shopping, housing, water, and sewage treatment. Provision of these goods and services will again result in employment opportunities, some of which will be filled by current residents and some by in-migrants.

Many of the socioeconomic impacts of a refinery depend on the extent and rate at which the new employment triggers population growth in the areas surrounding the facility. If most of the primary and secondary jobs are filled by local residents, in-migration will be minimal. If, on the other hand, most jobs are filled by in-migrants, the effects of the population change could be quite severe, especially in sparesely populated areas.

Rapid population growth can result in a higher demand for publicly and privately provided goods, infrastructure, and services. It can also result in higher local income; higher prices; and a change in the fabric and quality of life. The impacts of growth can be both positive and negative, depending on (a) the ability of local human and urban resources to meet higher levels of demand, (b) the size of the population influx relative to the existing population, (c) the quality of local management of the growth process, and (d) the willingness of the community to undergo major social changes.

FIGURE 38 SCHEMATIC OF COMMUNITY GROWTH INDUCED BY INDUSTRIAL DEVELOPMENT



When growth is too rapid, local resources cannot respond in a timely and efficient manner and a boomtown may result. Boomtown phenomena have been described in detail elsewhere. They include deficiencies in local facilities and services, housing problems, social disruption, and abandonment problems. On the other hand, an urban community with excess capacity in public and private infrastructure may experience only moderate impacts from growth. Likewise, impacts can be modified and controlled through planning, cooperation between the refining company and public officials, and timely and adequate provision of capital for private and public sector expansion even in smaller communities.

The settlement patterns of in-migrant workers will affect the level of impact caused by industrial development. Workers in a refinery located in a County will choose between housing from residential areas both in and outside the county. A number of factors affect the worker's locational choice, including commute distance, price and quality of available housing, and the availability of publicly and privately provided goods and services. If a facility is located near a number of attractive communities, the population inflow may be spread over a wide enough area to minimize (or at least partially alleviate) the impacts. On the other hand, when a facility is located in an isolated rural area, the population inflow is likely to be concentrated in a few communities, and the resulting impacts will be much greater.

In order to gain a perspective as to how the community will be impacted by a refinery, it is necessary to gain some understanding of the sensitivity of the projected needs in various service categories (education, housing, medical services, etc.) to different assumptions about the development. If plant location is not tied down, what difference might it make if various alternative locations are chosen? What if the development is delayed some period of time? How sensitive are community impacts to plant size? Knowing some of these effects can allow the community to articulate and negotiate what type of develop- is in its interest as opposed to other approaches which might be particularly difficult to handle.

However, be aware of the effects which growth and development will have on the community's resource base. It is easy to see that certain sources of tax revenue will expand. But this should not be overplayed. Dollar shortfalls are usually predictable in the early years of development, and sometimes can be projected for years. Therefore, consider opportunities that growth might bring for expanding non-tax revenues. Evaluate the opportunities for strengthening community organizations and their potential in helping to meet community needs. Consider the energy companies and their personnel and management expertise that might help serve the community. Consider state level offices aimed at assisting impacted communities. Identify federal programs for which an impacted area might be eligible. Look to private companies that might do business, and serve the community, in a growing area.

Another part of the assessment process involves development of a close working relationship between the community and the refining company. It is imperative that local residents, officials, planners, and the refiner be aware of the concerns of the other groups so that a consistent effective line of communication can be established. The following problems are presented to assist the community in establishing this relationship.

(1) Representatives of the refinery company who are planning work in the area should be brought into the planning and evaluation process early. In so doing, they will become aware of the community's needs and problems. Two means of accomplishing this are:

- Actively seeking to involve representatives from the refining company in the planning and impact assessment process;
- Assigning such representatives some meaningful role in the community growth management effort beyond that of simply providing information.

Communities must recognize that the companies' plans frequently change. Therefore, develop informal contacts to keep up-to-date on changes and avoid pressing for a single static projection. Rather focus on gaining an understanding of the factors being weighed by the company itself.

Finally, an attempt should be made to inform the companies about the process of community development. The most important point to convey is the lead times required in expanding community facilities and services.

(2) For the refinery facility likely to occur in your area, become familiar with the steps required of the refiner before construction can begin:

- Site selection procedure
- Plant siting permits
- Environmental impact statements
- Governmental plan approval.

(3) Learn as much as possible about the nature of the construction and operational phases. Where the refinery technology is not completely new, observe how similar refinery developments have occurred elsewhere.

- Obtain available studies.
- Contact other local officials in communities where similar operations are underway.
- Talk with company representatives.

Attempt to obtain data on plant employment, wage scales, skill requirements, attractions of support industries, plant working conditions, employment turnover, employment stability, and other factors that may signal the level and characteristics of a population influx that might accompany a refinery development.

Where possible, correlate the above data with the scale of output. This will allow you to assess the impacts that might arise under a variety of assumptions about how large a development might occur in your area.

(4) Refining companies are frequently unsure about just how development will occur until shortly before the start of construction. Therefore, avoid the temptation of delaying impact projection until the future becomes clear. This may be too late. This type of planning would allow one to identify points and times in the development process where the local community has the opportunity to raise problems regarding its needs and to seek assurances that such needs are met before the development can continue.

(5) Finally, to the extent possible, one should identify the range of impacts that might occur over a number of time horizons. This is vital for developing the community's plans and specific budget priorities.

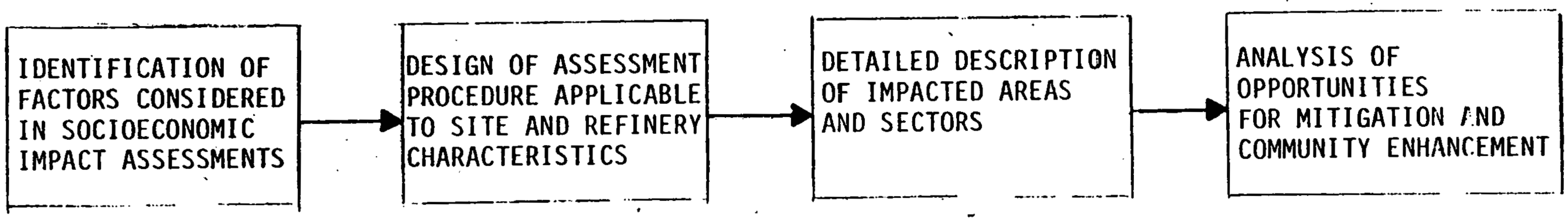
3.9.3 Description of the Socio-Economic Impact Assessment Procedure

To this point, the discussion has focused upon the overall impacts that a refinery may have on a community, and the general actions that should be considered by a community to predict, analyze and manage these impacts. The remainder of this section will present the impact assessment process and the impact analysis methodologies in greater detail.

The purpose of impact assessment is to foresee the consequence of a particular proposed action in the sense of defining what difference the action will make. The definition of impact, therefore, is the difference between conditions as they would exist without a refinery compared to conditions as they would exist with a refinery. The assessment process is oriented to defining these two sets of conditions so they can be compared.

The basic, socio-economic assessment procedure is shown in Figure 39. It is assumed at this point that the construction site has already been selected. The procedure provides an orderly approach to developing the impact assessment. As shown the procedure consists of identifying the areas of concern, developing the criteria

FIGURE 39 SOCIOECONOMIC EVALUATION PROCEDURE



and procedures for projecting and assessing impacts upon the areas of concern, describing and interpreting the impacts, and developing the methods of managing and dealing with projected impacts. By following such a procedure, it is assured that the final assessment will be complete and accurate. The following discussion details the individual steps.

3.9.3.1 Identification of Factors to be Considered

While many factors may be considered for assessment by a community, there are essentially seven basic elements of a community that must be studied and the impacts of the refinery on these elements must be projected and evaluated. These are:

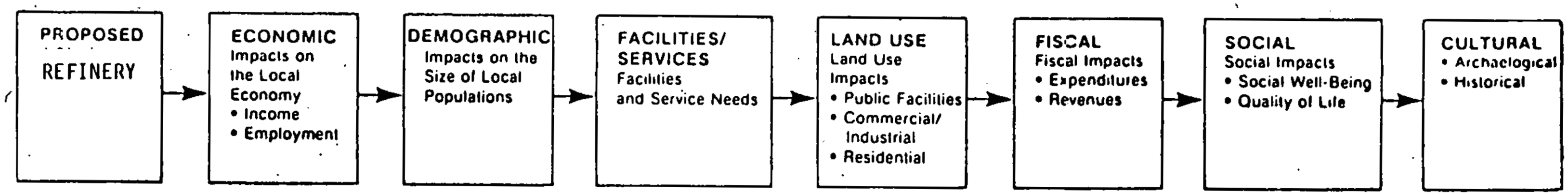
- area economics
- demographic (population)
- facilities and services
- land use
- fiscal
- social
- cultural.

While these may not be the only elements of the community to be affected by the siting of a refinery, they generally are those which the vast majority of communities will consider to be of greatest importance.

Figure 40 shows the order in which these elements are analyzed. The figure shows the elements not as district entities, but as being interrelated. For example, the refinery will have its greatest direct impact on the area economics, which also includes such items as employment and income. A change in employment opportunities will then affect the population of the area. Thus, by first assessing the area economics, the data is generated that will be used to project the impacts on the area population. The following describes, in detail, the elements and their interrelationships.

Area Economics - This element involves the overall economy of an area. This includes employment income and other related factors.

FIGURE 40 ORGANIZATION OF THE ANALYSIS OF IMPACTS ON THE HUMAN ENVIRONMENT



Source: Reference 36

Demographic - This element is concerned with the size and composition of the area population. This involves the present and projected size of the general population, the number of households, number of school age children, and other population subgroups. Since the major factor affecting the population of small areas is migration, and since migration is heavily influenced by the availability of employment opportunities, the population analysis is logically related to the economic analysis.

Facilities/Services - This element is concerned with the facility and service requirements implied by the economic and demographic analysis. Attention is given both to those facilities and services provided primarily by the private market but having significant public sector linkages, such as housing and health services, and to those facilities and services usually provided by the public sector like public safety, water supply, wastewater treatment, transportation, or recreation.

Land Use - The land use element involves how available land will be used and is the cumulative result of economic, demographic, and social forces acting on an area. Included in this element is the effect on wildlife, topography etc.

Fiscal - This element relates to public sector expenditures and finances. Completion of the facilities/services analysis will generate most of the information necessary to analyze this element. The economic and demographic analyses simultaneously provide much of the input to projecting public sector revenues. In combination, therefore, the fiscal analysis looks at the implications of given levels of economic and demographic activity in terms of their effects on both the income and the expenditure side of the public sector budget.

Social - This element involves two areas. The first is the existing social structure and how it will be affected by the proposed refinery. The second is the cumulative implications of the proposed refinery on individuals. To deal with these areas requires that there be a summation of all the various impacts and that an overall evaluation be made of the effect of an action or a change on the well-being of the residents of an area.

Cultural - This element deals with local culture and the impact analysis is developed around two major subcomponents: history and archaeology. The archaeological subcomponent deals with information concerning the life and culture of people who lived prior to written history while the historical subcomponent addresses people and events within the recorded past.

3.9.3.2 Design of the Impact Assessment Procedure

Once the elements to be assessed have been identified, a procedure must be established to analyze the impact the refinery will have upon each one. This will allow for (1) an assessment of the direct impact of the refinery on each element; and (2) provide the data necessary to analyze other elements. Once this procedure has been completed for each detailed element, the overall impact that the refinery will have on the community may be ascertained.

The general impact assessment procedure to be conducted on each element is shown in Figure 41. This method may not be directly applicable to every community and thus may be modified to meet site specific needs. The procedure consists of six steps, with the results of each step being dependent upon the data derived in the previous steps. Therefore, each step is interrelated with the others and does not stand alone as a separate, distinct function. The steps are detailed as follows:

Step 1. Description of the Existing Environment - This is an evaluation of the existing environmental conditions with emphasis given to areas that are expected to be the most affected by the presence of a refinery. This will establish the basis from which projections of future conditions will be made.

Step 2. Evaluation of Future Conditions without the Presence of the Proposed Refinery - This step projects from the information on the existing environment developed in Step 1, the future environmental conditions

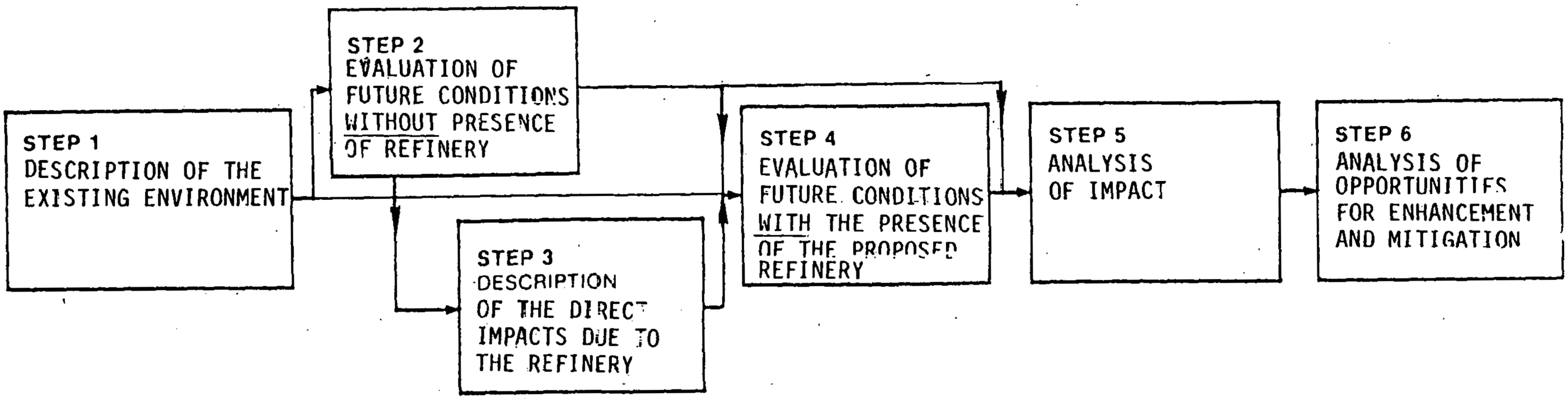


FIGURE 41 STEPS IN THE IMPACT ASSESSMENT PROCESS

Source: Reference 36

of each element as they would exist in the absence of the refinery. Projections are made for both the near and distant future. This step will be important in two ways. First, it will project how the absence of the refinery will affect the size of future impacts. For example, if area unemployment rates are low without the refinery being built, the future population would be expected to increase, due to migration into a desirable work area. However, if area unemployment is high without the refinery, future population growth would be lower, as the area would be less desirable in terms of available jobs. Second, future conditions in the absence of the refinery will also affect the significance of an impact of a given size. For example, the significance of a given reduction in wildlife habitat due to the construction of a refinery will depend on the condition of the habitat if the refinery were not constructed. Similarly, the significance of a given increase in high school enrollments will depend on the rate of utilization of existing facilities if the refinery had not been constructed. In addition to the direct contribution of this step (Step 2) to the results of the impact analysis, carefully executed projections <u>without</u> the proposed refinery will usually mean that much of the work required to make projections <u>with</u> the proposed refinery (Step 4) will already have been done.

<u>Step 3. Description of Direct Impacts Due to the Refinery</u> -This step is used to assess the direct impacts a refinery may have on the human environment of the area. Figure 42 shows a matrix which exemplifies this step. As shown, the various refinery activities associated with construction and operation are listed against various aspects of the human environment of the area. The impact of each refinery activity on each aspect of the human environment is then assessed. Completion of Step 3 is accomplished by using data generated in Steps 1 and 2, which provide the base information on the human environment without the presence of the refinery.

<u>Step 4. Evaluation of Future Conditions with the Presence of the Proposed Refinery</u> - In this step, projections of the future environmental conditions as they would exist with the refinery are constructed. This is based upon the evaluation of existing conditions (Step 1), the projected conditions without the refinery (Step 2) and direct impact assessment (Step 3).

FIGURE 42 REFINERY ACTIVITY IMPACT MATRIX

		HUMAN ENVIRONMENT	Social – Aesthetic and Human Interest – Views & Vistas	Social – Aesthetic and Human Interest – Wilderness Qualities	Social – Aesthetic and Human Interest – Landscape Designs	Social – Aesthetic and Human Interest – Unique Physical Features	Social – Aesthetic and Human Interest – Parks & Reserves	Social – Aesthetic and Human Interest – Rare & Unique Species & Ecosystems	Social – Aesthetic and Human Interest – Historical or Archeological Sites	Social – Public Health – Ambient Noise Levels	Social – Public Health – Drinking Water	Social – Public Health – Air Quality	Social – Public Health – Safety	Economic – Employment – Short Term	Economic – Employment – Long Term	Economic – Housing – Short Term	Economic – Housing – Long Term	Economic – Infrastructure – Transportation Network	Economic – Infrastructure – Waste Disposal	Economic – Infrastructure – Utilities	Economic – Infrastructure – Government Services	Economic – Infrastructure – Safety Services	Economic – Land Value – Residential – Adjacent	Economic – Land Value – Residential – Remote	Economic – Land Value – Agricultural – Adjacent	Economic – Land Value – Agricultural – Remote	Economic – Land Value – Commercial – Adjacent	Economic – Land Value – Commercial – Remote	Economic – Land Value – Industrial – Adjacent	Economic – Land Value – Industrial – Remote	Economic – Local Economy – Government Fiscal Effects	Economic – Local Economy – Business Activity	Physical – Land & Water Use – Wilderness and Open Spaces	Physical – Land & Water Use – Wetlands	Physical – Land & Water Use – Forests	Physical – Land & Water Use – Grazing	Physical – Land & Water Use – Agriculture	Physical – Land & Water Use – Residential	Physical – Land & Water Use – Commercial	Physical – Land & Water Use – Industrial	Physical – Land & Water Use – Designated Lands	Physical – Recreation – Hunting	Physical – Recreation – Fishing	Physical – Recreation – Boating	Physical – Recreation – Swimming	Physical – Recreation – Camping	Physical – Recreation – Hiking
CONSTRUCTION		Ground Clearing & Reshaping																																													
CONSTRUCTION		Equipment Use																																													
CONSTRUCTION		Channelization, Shoreline Modification, and Other Water-Related Activities																																													
CONSTRUCTION		Material Movement to Site																																													
CONSTRUCTION		Influx of Temporary Work Force																																													
CONSTRUCTION		Public Service Requirements																																													
CONSTRUCTION		Land Committed to Facility																																													
CONSTRUCTION		Other																																													
REFINERY OPERATION	Crude Oil Receiving & Storage	Hydrocarbon Emissions																																													
REFINERY OPERATION	Crude Oil Receiving & Storage	Leaks & Spills																																													
REFINERY OPERATION	Crude Oil Receiving & Storage	Visual Intrusion																																													
REFINERY OPERATION	Crude Oil Receiving & Storage	Human Activity Disruption																																													
REFINERY OPERATION	Crude Oil Receiving & Storage	Accidents																																													
REFINERY OPERATION	Plant Operation	SO_x Emissions																																													
REFINERY OPERATION	Plant Operation	NO_x Emissions																																													
REFINERY OPERATION	Plant Operation	Particulates																																													
REFINERY OPERATION	Plant Operation	Hydrocarbon Emissions																																													
REFINERY OPERATION	Plant Operation	Other Emissions																																													
REFINERY OPERATION	Plant Operation	Leaks & Spills																																													
REFINERY OPERATION	Plant Operation	Solid Waste																																													
REFINERY OPERATION	Plant Operation	Cooling Water Consumption																																													
REFINERY OPERATION	Plant Operation	Process Water Consumption																																													
REFINERY OPERATION	Plant Operation	Wastewater Effluents																																													
REFINERY OPERATION	Plant Operation	Visual Intrusion																																													
REFINERY OPERATION	Plant Operation	Accidents																																													
REFINERY OPERATION	Product Storage & Shipping	Hydrocarbon Emissions																																													
REFINERY OPERATION	Product Storage & Shipping	Leaks & Spills																																													
REFINERY OPERATION	Product Storage & Shipping	Visual Intrusion																																													
REFINERY OPERATION	Product Storage & Shipping	Human Activity Disruption																																													
REFINERY OPERATION	Product Storage & Shipping	Accidents																																													

Source: Reference 38

Step 5. Analysis of Impact - The projections with and without the refinery are compared in this step in order to define the overall impact that the refinery will have on the community. Once these impacts and comparisons are made, their significance can be evaluated from the perspectives of the various interested parties, and the benefits and liabilities of the refinery for the community can be assessed.

Step 6. Analysis of Opportunities for Enhancement and Migitation - The final step in the assessment process evaluates the impacts analyzed in Step 5 and examines opportunities and defines the methods the community may use for increasing and maximizing the beneficial effects (enhancement) and softening the adverse effects (mitigation) that the refinery may have on the community. Care must be exercised to consider the benefits of mitigation or enhancement relative to the costs incurred in achieving the benefits. Enhancement and mitigation is discussed in detail in Section 3.9.5.

3.9.4 Methods for Analysis of the Community Environment

The preceding discussion has centered upon defining the overall procedure that may be used to complete the assessment of the impacts that a refinery may have if it were built in a given community. This section will define some of the methods by which each of the seven elements (section 3.9.3.1) may be analyzed to complete the impact assessment procedure shown in Section 3.9.3.2.

The purpose of this section is to present overall methodologies that may be used for analysis of the seven community elements, as specific data would require specific site information. In order to present the methods and show how these methods address the fact that the seven elements are interrelated, the discussion of each element has been organized around the following topics as defined below:

- Question and Issues -- What should be the concerns of the local planner and what are the critical questions to be addressed?
- Description of the Existing Environment -- What are the relevant characteristics of the existing environment and how can they be described? (Figure 41, Step 1)

Projections of the Impacts - Descriptions of the techniques available to project future community conditions with and without the proposed refinery (Figure 41, Steps 2, 3 and 4)

Impact Analysis -- Description of the questions and methods that can be employed to compare and evaluate the projected impacts and make certain that all critical issues have been addressed and that the analysis is sound. (Figure 41, Step 5).

3.9.4.1 Area Economics

Questions/Issues

The economic issues that must be addressed concern area employment and income.

Will the proposed refinery construction alter levels of total employment and total income in the area?

What will be the distribution of the changed employment and income levels? Will it accrue to existing residents of the area or to in-migrants?

Will the changed level of labor demanded result in fuller utilization of presently underemployed persons? What will be the effect on per capita income?

What will be the effect on the number of unemployed persons in the area?

Will any existing employers be adversely affected?

Will the refinery bring growth and development?

Answers to these questions will allow the impact assessment to deal with two related but distinct phenomena -- growth and development. Will the construction of the refinery require a larger number of persons in the area? If so, in-migration may be required which will generate growth. Growth can take place, however, with little or no development; i.e., existing residents may be unaffected by the growth or may even be adversely affected. Development is used to mean fuller utilization or enhancement of existing resources such that per capita incomes or earnings increase. This could come about from occupational upgrading; from increased levels of utilization, either in the form of a larger proportion of the population joining the labor force, from longer hours, or from increased productivity in existing occupations due to technological change; or from productivity increases due to increased supplies of other factors of production with which labor can work.

Methods for Describing the Existing Economic Environment

The first issue that must be addressed in describing the existing environment is the definition of the study area. In cases where the impact assessment is oriented to a particular place, the study area would be defined as the immediate local area and the fact that the refinery might affect other areas would be of no consequence.* In other cases, the impact assessment will be oriented to an action (e.g., a zoning ordinance or construction of a regional park) and it will be necessary to define the appropriate area within which the impact of the action should be studied.*

In those cases where study area definition is an issue, two kinds of criteria will have to be jointly considered. The first relates to data availability, while the second relates to the geographic extent of the area within which significant impacts will be felt. There are no current economic data compiled for subcounty areas. Data for subcounty areas can be obtained from census tapes,** but they are only of limited value for many areas. As a result, the study area will usually consist of a county or a group of counties.

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* It must be noted that the study area delineations appropriate to different components of the impact assessment will usually vary.

** Department of Commerce, Bureau of Labor Statistics.

A study area is usually defined with principal reference to the residential pattern of persons employed in the construction or operation of the proposed refinery. This suggests defining the study area based on ideas such as the boundaries of the local labor pool or the extent of the daily commuting field. Daily commuting fields with a radius in the 60 to 75 mile range are not uncommon, especially during the construction phase. For most purposes, therefore, the study area can be defined to include all counties containing communities from which a significant number of workers would commute daily. The definition of significant will depend both on community size and on project size. Particularly useful, if available, is evidence on actual commuting behavior from prior projects in the same general area as the proposed refinery.

Once the study area has been defined, it is necessary to describe current area employment, income, and labor market conditions in the study area. The decennial census provides a useful starting point for employment data. Data on total employment provides information on the long-term trend in the overall level of economic activity while much can be learned about the structure of the regional economy by studying employment disaggregated by industrial sector.

Data for intercensal years is available from The Bureau of Economic Analysis (BEA) of the U.S. Department of Commerce and the state employment security division. BEA prepared employment figures for each state and county as part of its Regional Economic Information System (REIS) while each state publishes monthly data on employment by industrial sector. County Business Patterns published by the U.S. Deparment of Commerce is a third source that provides annual data on employment and payrolls by county. The data are published with about a two-year lag and have the advantage of showing a higher level of industrial disaggregation for larger counties.

Detailed income data are available in the census and give an opportunity to analyze the sources of income in a county; the distribution of income among persons; and the relative position of the county compared to regional, state, or national data. It must be realized, however, that the amount of change that could take place in counties over a ten year span could make past census data of limited value. It is here, once again, that the BEA data are particularly helpful. They present county personal income and per capita personal income annually. Per capita income in the study area can be divided by per capita income for the United States to get a measure of the relative income position of the area and to get an indication of the way in which it is changing from year to year. Further, because the labor and proprietors' income is disaggregated by industrial sector, it is possible to identify those industries responsible for the major contributions to the economy of the county. It is also possible to see the role of non-labor income, especially government transfer payments (like social security or welfare payments), in supporting the local economy. Average annual earnings per wage and salary employee can also be derived by dividing income for each industrial sector by employment by sector. This provides additional information on the role of different sectors in the economy of the study area as well as providing earnings information useful for the impact analysis.

Having evaluated current area employment and income, the remaining part of the description of the existing economic environment that requires description is the labor market. This requires analysis of the supply of labor (the labor force) and of the relation of the supply of labor to employment to determine the extent of unemployment. Unlike employment where there is good information based on regular reporting requirements for all employers, the small area data on the supply of labor is much less precise. Two methods are used to estimate the existing labor force. One method uses the number of unemployment insurance claimants through a long series of steps to a final estimate of unemployment. The labor force (LF) is then calculated as the sum of employment (E) plus unemployment (U).*

* Given that county unemployment rates are currently an input into federal funding formulas, all states are required to produce county specific estimates of LF, E, and U. The unemployment rate is then calculated as U/LF. These data are available from the state employment security divisions.

A second method is to conduct a survey of a sample of households and determine directly whether they are in the labor force. This technique is limited, however, in that the resulting estimates, particularly for small areas, have very low reliability unless the sampling proportion is very high. In such cases, the survey becomes prohibitively expensive.

Further detail and description of the existing economic environment can be obtained by applying standard evaluation methods. Three commonly used methods are the economic base, input-output[77] and econometric[78] approaches. Each approach employs a specific method of organizing economic information. For purposes of this workbook, the Economic Base Approach will be presented and described as it is particularly applicable to smaller community assessments that are based on limited data.

The Economic Base Approach to analying the impact of a refinery on the existing economics of a community is popular mainly because it is relatively easy to evaluate. The approach provides information concerning the areas existing economic base and its capacity to satisfy additional employment and income requirements. The approach is based upon the fact that local economies respond to two types of demands, namely, demands which originate within the local economy and demands which originate from outside the local area due to activity which takes place within the local area. Agriculture and mining are examples of basic activities that generate income from demands originating outside the local economy (i.e., nationwide sale of farm produce) and that will generate demand within the local economy (local servicing of farm equipment). Therefore, a portion of the local economy will go toward satisfying local demands and a portion will go toward satisfying outside demands.

The presence of a refinery will, for example, through its impact on area growth create an increased demand for goods and services. The demand must be satisfied by that portion of the economy that satisfies local needs or, if this is inadequate, by shifting a portion of that part of the local economy that currently satisfies the demands that originate from outside the local area (export base). By employing the economic base approach it is possible to evaluate the status of the existing community export base and determine the impact that the refinery has upon this export base, and thus the assimulative capacity of the community.

Likewise, existing employment can be analyzed by this approach. Total employment can be categorized as basic and nonbasic. Basic employment is that employment generated by demands (or other forces, i.e., political decisions) that are external to the local economy, and nonbasic employment is that employment that responds to levels of demand originating within the local economy.[75]

While the conceptual distinction between basic and nonbasic employment can be established, there are practical problems associated with actually dividing employment into these two components. There are three approaches to the problem.[76] Primary data can be collected from local firms on the origin of the demand for their products. Secondary data (such as employment by industry) can be used to make inferences about the basic/nonbasic character of local firms. A third alternative is to classify firms on an a priori basis depending on the industry together with any special knowledge of the firm or its products.

For most small counties, identification of the important basic activities presents few difficulties. All major employers can be easily identified and the basic/nonbasic character of their businesses can be determined through personal interviews. As the economy becomes larger and more complex, however, cost considerations require that heavier emphasis be placed on secondary as opposed to primary data.

All of the techniques based on secondary data rely to some extent on the observation that nonbasic activity should be distributed geographically in about the same way as the variables that induce it. If there is a relatively heavy concentration of activity of a particular type in a given location, therefore, the inference is that some of the activity is basic. For example, if several counties of about the same size (either in terms of total population, or income or employment) had employment in the service sector of close to 200 but one county had employment of 300, the supposition is that the difference must be basic (perhaps tourist related).

The third technique, (*a priori* approach,) uses information about a firm's industry and products together with some locally derived information and classifies the firm accordingly. Most states prepare a directory of manufacturers which gives enough information about each manufacturing firm in each county so that this approach can be used effectively.

- Projection of Impact

Economic Projections without the Proposed Refinery

Projections of the economy of the study area without the proposed refinery must be made so that projections with the proposed refinery can be compared to this baseline. This step need not involve undertaking an elaborate or detailed analysis. It is extremely important that the baseline be carefully considered, however, because the impact analysis can be very misleading without it. For example, the impact of a project may be to cause the population of an area to be larger by 200 persons than it would otherwise be. The significance of this change will be very different, however, for a region that has been losing population compared to a region that has been growing. For a region that has been losing population, for example, the implication of a 200 person impact may be that population will remain constant (instead of falling by 200). For a growing community, however, the project will mean growth 200 persons greater than would otherwise have occurred. In this case, there will be new demands for services and facilities while in the former the impact may only cause existing facilities to be more fully utilized with no required expansion.

There are several different methods by which economic projections of the study area without the refinery can be made. As with the description of the existing environment, the economic base approach can be used for this analysis focusing on the major basic industries in the study area. The objective is to find out why the industry exists in the area, whether it is presently profitable, and whether it can be expected to continue to be profitable. If it is expected to be profitable, its potential for growth is examined, either in terms of expansion of existing firms or in terms of location of new firms in the area. In the case of an industry which does not appear to have potential for expansion, the possibility of declining levels of employment should be examined. Information should be developed on each basic industry, culminating in an explicit set of overall employment projections for that industry. These are then totaled for each industry to project the total employment. A large amount of this type of information is generally available. The most comprehensive sources include:

(1) Knowledgeable Individuals within the Local Industry
(2) State Universities
(3) Relevant State or Federal Agencies
(4) Projections of National Employment by Industry

As described in the description of the existing economic conditions, employment is divided into basic and non-basic. These must be individually projected into the future. An immediate problem is that the jobs in the various local sectors do not have the same effect on the local economy because their wage levels are different. Federal and mining jobs will have a much larger weight, for example, than the relatively low-paying jobs in the trade and service sectors. The easiest way to deal with this problem is to introduce the concept of basic income. Basic income is simply the income arising from basic employment. It is calculated by multiplying the number of basic jobs by the average labor earnings per employee for that sector for the county or counties being studied.*

* See examples, Reference 36, pp. 27-79.

Once basic income (or employment) has been calculated, the next step is to consider the amount of nonbasic activity that will occur in response to the change in the economic base. This phenomena is termed the multiplier process. The multiplier exists because of the causal relationships that exist between production, income, and demand. If mining activity increases, for example, due to national market conditions, this increase in basic income would lead to local expenditures which would cause a further increase in local production (nonbasic) which would further increase income and expenditures, and so on. Because of leakages to taxes between production and income, and leakages to saving and to purchases of non-locally produced goods and services between income and local expenditures, each successive increase in the production, income, expenditure cycle becomes smaller and nonbasic activity will eventually stabilize at a new higher level in response to the higher level of basic activity.

If the eventual increase in nonbasic income were $60 subsequent to an initial change of $100 of basic income, the ratio of the total change in income ($160) to the change in basic income ($100) is called the <u>income multiplier</u>. In this example, the income multiplier would have the value of 1.6. (160÷100 = 1.6) Employment multipliers are defined in the same way. They represent the total change in employment (basic plus nonbasic) divided by the change in basic employment:

Another method of obtaining employment and baseline projections include the use of projections prepared by other persons. There are national projections, such as the OBERS projections prepared by the Bureau of Economic Analysis in collaboration with the Economic Research Service of the U.S. Department of Agriculture, but these are unlikely to be sufficiently tuned to the realities of the region to be of much help to local planners. Other alternative methods consider the use of projections prepared by state organizations or extrapolation of past trends. If there is evidence that the forces that will act on an area in the future will be similar to those that have affected the region in the past, trend extrapolation may be a very reasonable way to proceed.

Other, more complex analysis techniques will often be applied to the problem of making baseline projections. They are not given much emphasis here because they require a higher degree of technical expertise to implement than does the economic base methodology or the other methods previously mentioned.

Description of the Direct Impacts of the Proposed Refinery in Terms of the Local Economics

Requirements from Industry or from the Developer - The quality of the information developed describing the proposed refinery will be a major determinant of the credibility and usefulness of the impact analysis. If the project is 5 to 10 years away, precision will not be an issue as long as the estimates are of the correct order of magnitude.

As the project becomes more imminent, however, and planning decisions are made in anticipation of impact, it is critical that the developer be encouraged to be as specific as possible about construction and operation requirements. It should be remembered as this information is pursued that the owner of the project may know very little about the details of project requirements. The key source of information will be the architect/engineer hired by the project owner and it is worthwhile to try to deal directly with the architect/engineer to get a description of project requirements. The desired information is as follows:

<u>Construction Labor Requirements by Year</u> (in person years)
- Administration and engineering (owner's representatives and architect/engineer)
- Construction
  - Administrative and Supervisory
  - Manual Workers by Craft

<u>Operation Labor Requirements by Year</u> (in person years)

<u>Total Cost of Construction</u> (constant dollars)
- Labor
- Materials (itemization of major requirements)
- Equipment

Operating Costs

Labor

Materials (itemization of major requirements)

Equipment

The construction and operation labor estimates are very important for the impact analysis. Care has to be exercised with the labor requirements estimates to distinguish scheduling estimates done in terms of person years and estimates of the number of persons who will actually be on the site at any given time. Both concepts are relevant, but they must not be confused.

Equipment purchases are likely to have little or no effect on either the local or the regional impact area. Materials purchases on the other hand, bear closer inspection. If significant quantities of cement, reinforcing steel, asphalt, fuel oil, etc., are going to be purchased locally, a direct attempt should be made to investigate the local employment and income effects of the purchase. In occasional cases, the effects will be large enough (e.g., doubling of a batch plant) that they should be added to the impact projections.

Local/Nonlocal Composition of the Workforce The next step in describing the direct impact of the refinery is to make assumptions about the composition of the construction and the operating workforce between local and nonlocal workers.* The supply of locals will depend on the number of workers with the appropriate skills who reside within the daily commuting region of the project; on the access to the project from the population centers in the daily commuting region; on the total compensation package on the project including wages, opportunities for overtime, and travel or subsistence allowance; on the alternative employment opportunities that exist within the region; and on the influence/prevalence of unions in the area.

* A local worker is defined here to be the one who commutes daily to a project from the same place of residence he/she occupied prior to the beginning work on a project. A nonlocal worker is one who has changed place of residence from which he/she commutes daily in order to work on a project.

Clearly, there is substantial variation and the results of the impact analysis will depend heavily on the assumption made. In general, the more distant in the future and the less specific a project, the stronger the case for relying on averages based on existing project data. As the project gets closer and closer, however, and as the quality of the information with respect to the labor requirements becomes more detailed, a great deal can be learned about the likely number of locally available electricians, operators, etc., by talking to local union business managers, contractors with experience in the area, and to other persons familiar with local labor market conditions. These interviews should present an estimate of project demand by craft (e.g., 150 electricians in year 4) to someone knowledgeable about the local labor market for electricians. Once the location of the project has been described and some thought has been given to other projects which may be competing for the same labor, a reasonable estimate can usually be made of the total local supply and of the number that would work on the project in question.

Once an estimate has been made of the number of local workers the daily commuting region will be able to supply, the required number of inmigrating nonlocal workers can be estimated by subtracting the estimate of local workers from the estimated total labor requirement. At some point, it will be necessary to estimate where the inmigrating non-locals will live, but that issue is discussed later.

Economic Projections with the Proposed Refinery and the Measurement of Impact

The economic projections with the proposed refinery should concentrate on employment because it is the critical link to the demographic impacts. While the employment requirements of the proposed refinery may be reasonably easy to obtain, a more difficult problem is to determine if there will be any increase in nonbasic employment in response to the proposed refinery. The issues that have to be dealt with include the following:

The amount of nonbasic employment that will result from one dollar of basic income will be greater the larger the local economy.

The multipliers appropriate to construction worker income will be lower than those appropriate to basic income generated in the operations phase.

The income and employment multipliers will not usually be the same. If the basic jobs have systematically higher wages than the nonbasic jobs, the employment multipliers will be larger than the income multipliers

<u>Economic Multipliers</u> - Economic multipliers exist because part of the income received and then spent in an area becomes income for someone else. The size of the multiplier will depend on the proportion of income spent locally and on the proportion of local spending that becomes local income. In general, the larger and more diverse a local economy, the proportion of income spent locally will increase because more goods and services will be available, and the proportion of spending that becomes local income will be higher because more of the production and distribution process will have taken place locally. For example, if both a dairy farm and a dairy are located in an area, a large proportion of the money from the sale of a quart of milk will become local income. If neither the farm nor the dairy are located in the area, then the only local income generated from the sale would be the small net income going to the retailer.

The combined result of these factors is that more of a given amount of income will be respent in larger places and that more of what is respent will become income for someone else with the result that the multiplier will be larger. This principle is well understood, but the difficulty comes in making empirical estimates of the relevant relationship. Some form of an economic base model is, therefore, usually used to try to quantify these relationships.

The economic base approach is straightforward to apply assuming that counties are independent of one another, but a substantial problem arises when actually applying it to areas that are trade or service centers to large market areas. In these cases, part of the income in the trade center is in response to basic income in the smaller counties that constitute its market area. If the economic base multipliers are going to be correctly calculated, therefore, it is necessary to have an idea of the market area boundaries of the regional centers in the study area. If this basic income is ignored, the economic base of the county is understated and the multiplier is overstated.

The size of this income multiplier effect, as it is called, is determined primarily by two important factors: the marginal propensity to spend locally (c), and the fraction of sales that becomes local income (h). The general formula is:

$$\text{multiplier} = \frac{1}{1-(c)(h)}$$

The larger the value of the multiplier, the greater the secondary income benefits. The marginal propensity to spend locally is simply the fraction of total income spent on locally-provided goods and services. As such, it depends on the mix of goods available locally, relative prices between local and imported goods, the availability of imports, and the type of goods and services desired.

The marginal propensity to spend locally is a function of the number of local and nonlocal construction workers employed at the facility. If local construction workers are hired, then it should be assumed that their spending behavior will be no different than any other local resident. A difference in expenditure patterns arises in the context of nonlocal workers. First, nonlocal construction workers who are not married or are married and have their families with them, and who are similar to local residents in others respects, will spend a smaller proportion of their income locally than local residents. Secondly, a multiplier adjustment is required because some proportion of the nonlocal workers are married, but their families are living elsewhere. This group undoubtedly spends much less locally because a large proportion of its income is required for the support of families living in other places.

Combining these two effects yields an estimate that to the extent that there are nonlocal workers, local spending will be a smaller percentage relative to what it would be if local workers received the income.*

Assessing the Income Impacts of the Proposed Refinery - To calculate the total impact of the proposed refinery, the multipliers calculated can be applied to estimates of total basic income associated with the project.

The steps are as follows:

Use the estimate of the local/nonlocal composition of the construction force and the order of the county being investigated to estimate the appropriate income multiplier.

Use externally supplied wage data or BEA average earnings per worker in the construction or appropriate operations sector to estimate average earnings per employee (all in constant dollars).

Multiply the direct employment requirements by the earnings estimates to get basic income directly associated with the project.

Include any other basic income associated with the project, e.g., due to local purchases of materials.

Use the multipliers together with the basic income estimates to calculate the total change in income.

The example in Table 29 shows how these steps can be carried out for a hypothetically proposed refinery. Although this illustration presents a procedure for determining the basic and nonbasic income impacts in a

*Methods for adjusting the multipliers can be found in Reference 36, pp. 48-50.

TABLE 29 ASSUMPTIONS AND CALCULATIONS OF IMPACT FOR PROPOSED REFINERY
(200,000 BBL/DAY GASOLINE PRODUCTION REFINERY)

Assume:
1. Construction worker average earnings $14,000.
2. Construction period employment is 475 in year 1, 1424 in year 2, 1898 in year 3, 949 in year 4.
3. Operations worker average earnings $13,500.
4. Operations period employment is 192 in year 4, 768 in year 5 and thereafter.
5. 2nd order county, income multiplier = 1.66.
6. Construction force 50 percent local, 50 percent nonlocal.

Therefore, (50 x 1) + (50) (.7) = .85 and the appropriate construction period multiplier equals 1 + (.85)(.66)= 1.56.

7. No significant construction period purchase of materials or equipment locally.
8. Operation period materials purchases will result in $100,000 of basic income per year which is assumed to result in 10 local jobs.

Calculations of Income Impacts for Hypothetical Proposed Refinery

Col. 1 Year	Col. 2 Construction Period Employment	Col. 3 Construction Period Basic Income Equals Col. 2 x $14,000	Col. 4 Total Construction Period Income (Basic and Nonbasic) Equals Col. 3 x 1.56	Col. 5 Operation Period Employment	Col. 6 Operation Period Basic Income Equals Col. 5 x $13,500	Col. 7 Total Operation Period Income (Basic and Nonbasic) Equals Col. 6 x 1.66	Col. 8 Basic Income Due to Materials Purchases	Col. 9 Total Income Due Due to Materials (Basic and Nonbasic) Equals Col. 8 x 1.66	Col. 10 Total Income Col. 4 + Col. 7 + Col. 9	Col. 11 Total Nonbasic Income Col. 4 - Col 3 + Col. 7 Col. 6 + Col 9 - Col. 8
1	475	6,650,000	10,400,000	0	0	0	--	--	10,400,000	3,750,000
2	1,420	19,900,000	31,100,000	0	0	0	--	--	31,100,000	11,200,000
3	1,900	26,600,000	41,500,000	0	0	0	--	--	41,500,000	14,900,000
4	949	13,300,000	20,700,000	192	2,590,000	4,300,000	--	--	25,000,000	9,110,000
5	0	--	--	768	9,980,000	16,600,000	100,000	166,000	16,800,000	6,686,000
6	0	--	--	768	9,980,000	16,600,000	100,000	166,000	16,800,000	6,686,000
7	0	--	--	768	9,980,000	16,600,000	100,000	166,000	16,800,000	6,686,000

Source: Mittelhauser Corporation

community (or county), there are some variable components (i.e. average earnings and the construction period multiplier). The data which comprise these two components are region- and site- specific and are moreover a function of the influence of union jurisdiction and contractor hiring practices. Therefore, this illustration only exhibits the procedure for determining the income effects of a project and does not demonstrate the actual impacts induced by the development of a refinery complex. All subsequent discussions of impacts are only for illustrative purposes only and do not portend the socioeconomic impacts in any particulate region or county/community type.

Estimating the Employment Impacts of the Proposed Refinery - With the direct manpower requirements of the proposed refinery already estimated (Table 7, 8, and 9 in Section 3.4), all that remains is to estimate the nonbasic employment due to the proposed refinery. The potential increase in nonbasic employment can be calculated by dividing estimated nonbasic personal income by an average ratio of personal income to employment for the county. This is done in Table 30. Although this will provide an answer for potential nonbasic employment, it does so first through the calculation of the income generated in the basic and nonbasic employment sectors. This procedure can be speculative and moreover relies heavily on the availability and reliability of the data and assumptions required by the procedure.

Table 30

Estimating Potential Nonbasic Employment Impact for a Proposed Refinery

1. Calculate ratio of personal income to total employment from BEA data (assumed to equal $9,738 in this example).
2. Divide total nonbasic income (from Table 29) by $9,738.

	Col. 1	Col. 2
Year	Total Nonbasic Income	Potential Nonbasic Employment (Col. 1 ÷ $9,738)
1	$ 3,750,000	365
2	11,200,000	1150
3	14,900,000	1530
4	9,110,000	936
5	6,690,000	667
6	6,690,000	667
7	6,690,000	667
8	6,690,000	667

An alternative method of estimating employment impacts is suggested by HUD in Rapid Growth from Energy Projects[53] and is also proposed in the EPA Action Handbook[54]. Both reports suggest taking the number of construction workers times .6 to get nonbasic employment during the construction period (a total multiplier of 1.6) and to take operation workers times 1.5 to get nonbasic employment during the operation period (a total multiplier of 2.5). An example of this method applied to the refinery manpower requirements is presented in Table 31.

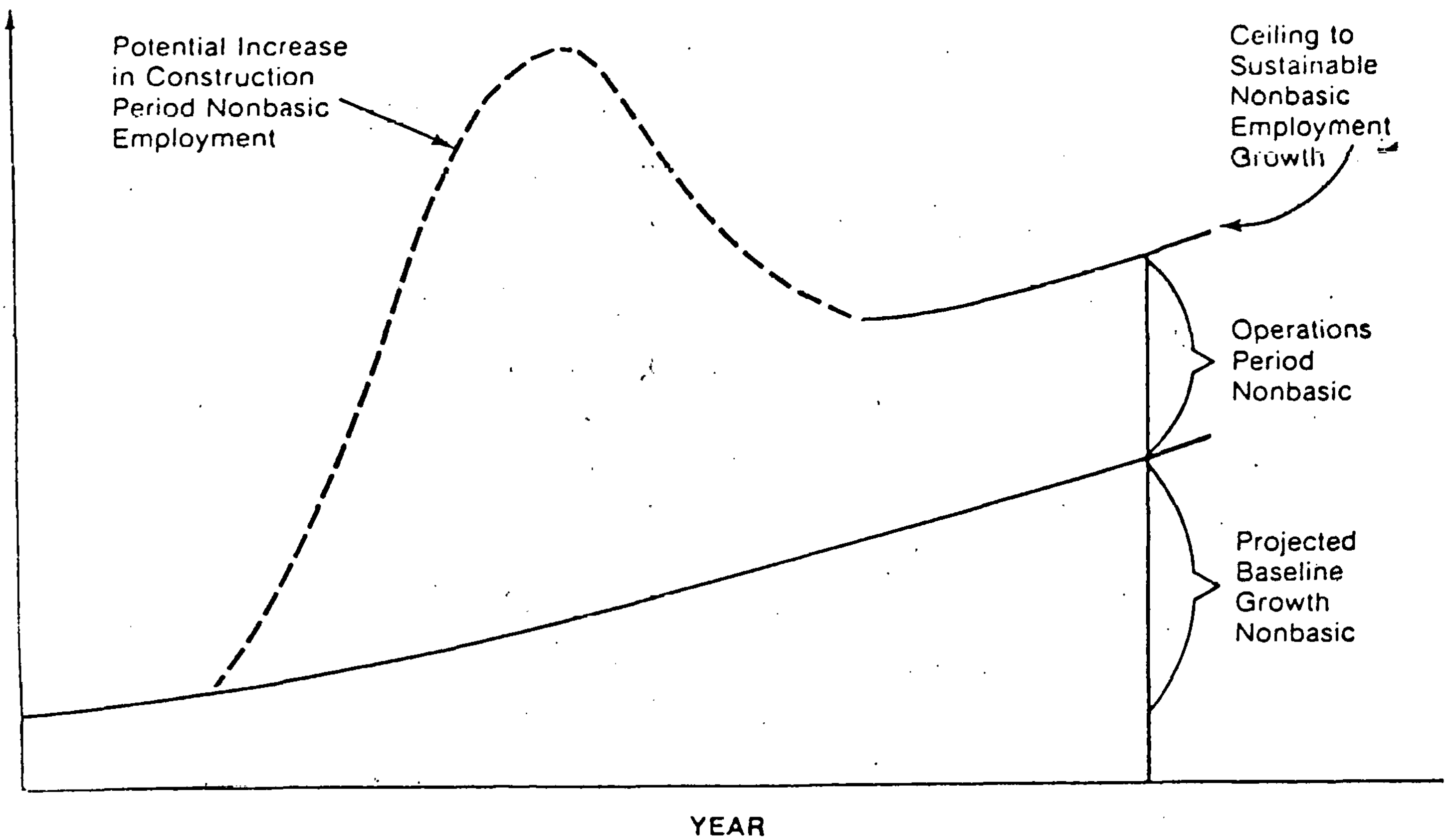
Table 31

Calculation of Nonbasic Employment using the HUD/EPA Method

Year	Col. 1 Construction Employment	Col. 2 Operations Employment (including 10 persons due to local materials purchases)	Col. 3 Nonbasic Employment (.6 x Col. 1 + 1.5 x Col.2
1	475	--	285
2	1,420	--	850
3	1,900	--	1,140
4	949	202	870
5	0	778	1,170
6	0	778	1,170
7	0	778	1,170
8	0	778	1,170

Regardless of how the potential increase in nonbasic employment is calculated, a major issue of interpretation and judgment arises at this point. The income calculations showed that 15.0 million of nonbasic income would result from the proposed refinery during the peak year (year 3). It is known that the direct income will be paid out as wages; it is also known that the income will be spent, and there are reasonably reliable estimates of the income multipliers that will result. It has to happen, therefore, that approximately $15 million of new personal income will be generated in the study area. Furthermore, it is known that since personal income per employee averages about $10,000 per person per year, $15 million is the equivalent of 1530 new jobs. What cannot be predicted, however, is whether local businessmen will respond by adding new employees or by more fully utilizing existing employees. Two facts stand out. The potential nonbasic employment estimates have to be viewed as an upper limit to the range of effects that could occur; much more likely is the possibility that the actual impacts in terms of numbers of employed persons will be smaller. Second, it is highly unlikely that local businesses are going to go to the expense of hiring and training employees to meet peak demand in year 3 only to lay them off in year 4 when basic income declines from its peak level. Equally unlikely is the possibility that nonbasic workers will in-migrate in large numbers during the peak years only to leave 1 or 2 years later. Much more likely is that employers will try to maximize their use of existing employees to meet what they recognize as temporary demand. Figure 43 illustrates the typical trend in the two principal nonbasic components: baseline nonbasic employment growth and operations period nonbasic employment growth.

FIGURE 43 POTENTIAL INCREASE IN CONSTRUCTION PERIOD NONBASIC EMPLOYMENT



There can be various configurations of this figure to account for rising baseline employment, falling baseline employment, or stable employment. Under this differing baseline condition, the potential and realized nonbasic employment differential will fluctuate, identifying the reaction of local business to the projected future. New retail stores, new doctors, and new state and local government employees will not move into town and require employees and land unless the medium term prospects (3-4 years) justify the expansion. It must be remembered, nevertheless, that the increased demand for nonbasic goods and services will exist during the construction peak regardless of the capacity of the local trade and service sectors. In cases where little expansion is justified, there will be particularly severe pressure on existing facilities with resulting frictions and problems.

The total impact of employment due to a refinery project is, therefore, the sum of construction period basic employment, operation period basic employment, basic employment associated with local purchases of materials for the proposed refinery and nonbasic (secondary) employment.

Impact Analysis

The following questions are those that should be addressed in order to evaluate the economic projections.

Have economic projections without the proposed refinery been made to provide a baseline for the impact evaluation?

Has a reasonable analysis been done of the labor requirements of the project and of the composition of the resulting construction and operation forces between existing residents of the area and new in-migrants? Do the local/nonlocal assumptions make sense in light of the baseline projections and in lights of other activity projected for the area at the time of the proposed refinery?

Are the economic multipliers appropriate to the size of the local impact area?

Is the size of the employment expansion associated with the construction peak appropriate to local expectations with respect to the project and to the capacity of the local economy to expand? Would this level of expansion appear feasible in light of local business conditions, the baseline projections, and the supply of local capital? Does the expansion appear reasonable in light of the growth that will be sustainable in the nonbasic sector in the long run?

Have opportunities for enhancement of local labor market effects been explored?

By accurately answering these questions, the reliability of the economic assessment can be evaluated.

3.9.4.2 Demographic

Questions/Issues

Accurate projections of the demographic implications of a proposed refinery are the cornerstone for most of the impact analysis. The overall approach recognizes that any increase in employment can only come about in one of three ways: a reduction in the number of local persons who are unemployed; an increase in the local labor force participation rate, or in-migration. Migration together with natural population increase (births minus deaths) determine population change. The purpose here, therefore, is to show how the analysis of economic impact can be used to project migration, and how the resulting migration estimates can be used to estimate population change. The specific questions that have to be answered include the following:

How many new residents will move to the area as a result of the proposed refinery?

What will be the age and sex composition of the new residents of the impact area?

In which communities will the new residents choose to live?

What are the baseline trends in population that would exist in the impact area in the absence of the proposed refinery?

Description of the Existing Demographic Environment

Data Sources

The only detailed source of population data is the decennial Census of Population. This source contains extensive information on the size, composition, and characteristics of the population. Published data are available for counties and for some cities. In general, the larger the place, the more detailed the social and economic information on its population. Additional data on subcounty areas is available from the Census Data Users' Centers identified in the previous section.

For the years following the last census, county population estimates are available from the Current Population Reports, Population Estimates and Projections, Series p-25, published by the Bureau of Census. These are estimates derived through a Federal-State Cooperative Program sponsored by the Bureau of Census. Briefly, the program operates as follows. The Bureau of the Census estimates the total population for each state. A designated state agency or university in each state then uses various Census-approved methods to allocate the state control total to counties. The estimates are made for July 1st of the year and are usually available during the spring or summer of the following year. The report published by the Census does not disaggregate the population into different ethnic or age/sex groups. It only contains total population by county.

Community population estimates for 1970 can be derived from a combination of published place data from the Census and special tabulations by Census Enumeration District when necessary. Subtraction of the sum of the community estimates from the total for the county gives an estimate of the rural population in the county. More current community population estimates may be available from a Special Census, but most of the updating from 1970 will have to depend on inferences drawn from secondary data sources such as school enrollments, new housing units completed, utility hookups, etc., and on the judgments of local planners and community leaders.*

A final characteristic of the existing environment that ought to be noted is the labor force participation rate of men and women in the study area. This measures the percent of the population that participates in the labor force (the sum of the employed plus the unemployed) and is only available in the decennial census volumes. It is particulately instructive to contrast the local participation rates with state or national rates to get an indication of the potential within the existing population to meeting higher demands for labor.

- Projection of Impacts

Methods of Projecting Population without the Presence of the Refinery

Projections of population without the proposed refinery are extremely important because they will provide data as to the areas of the community that may or may not be able to handle increased populations. An example of this point frequently occurs in the impact analysis of the school age population. Recent national trends towards reduced birth rates have started to show up in the form of declining school enrollments. As a result, there are many school systems for which an influx of school age children will avoid problems of consolidation and staff reduction rather than create problems.

The methods that can be used to project population are of several different kinds including:

General Methods

Trend Extrapolation Methods - This is a simple and frequently used method of projecting population to extrapolate

*A list of all areas for which a Special Census was made in 1975 is in Current Population Report, Series p-28, "Special Census."

recent trends into the future. The assumption is that the forces responsible for population change in the past will continue to behave in a similar way in the future.

Step Down Methods - A second general set of projection alternatives is to use projections developed by others and then to derive an estimate for the study area based on the estimate for the larger area.

Ratio to Employment - Another approach, if baseline employment projections (projections without the refinery) have already been made, is to assume that the ratio of population to employment will remain constant and to project population based on the employment projection.

Cohort Survival Methods

Cohort survival methods follow the number of persons in a set of age-sex groups or cohorts and then apply survival rates, birth rates, and migration assumptions to trace out the change in population over time. Although the mechanics of the cohort survival models are complicated, their logic is straightforward, and the questions at issue center on determining migration.

Some cohort-survival models assume no migration, others extrapolate past trends, while others use employment to help determine migration. Increasingly, methods are being standardized that pursue the third option of letting employment influence migration. The technique is built around three analyses:

Demographic Analysis - The demographic analysis begins with county population, disaggregated by age and sex. Age and sex specific survival rates are applied to each cohort (i.e., each age/sex specific group) to compute the effect of deaths on the county population. Age specific fertility rates are then applied to the females in each age group to estimate the number of births. This procedure yields an estimate of what is referred to as the "survived" population of the county.

Further adjustments are made in the demographic submodel if there are special subpopulations with distinct demographic characteristics or if there is migration into or out of the area related to factors independent of local labor market conditions (e.g., retirement migration).

Economic Analysis - The function of the economic analysis is to project employment on a place-of-residence basis. Frequently, economic base techniques of the type discussed in the Economic element of Section 3.9.3.1 are used.

Labor Market Analysis - The population calculated in the demographic analysis and the employment estimate calculated in the economic analysis are the principal inputs into the labor force and migration process. The locally available supply of labor is calculated by applying age/sex specific labor force participation rates to the population. If the supply of labor is in balance with projected employment, no migration is assumed to occur. If, however, there is an imbalance, inmigration or outmigration is assumed to occur until the imbalance is eliminated.

Because of the number of calculations required, cohort-survival analysis is impractical without the aid of a computer. At the same time, if the planner is going to keep track of the age and sex structure of the population, some form of cohort-survival analysis is necessary. The option of using an existing state or regional model for this purpose is, therefore, very attractive if something more than trend analysis is going to be attempted.

Land Use or Dwelling Unit Multiplier Methods

Another population projection method frequently used in city or subdivision planning is the Land Use Multiplier Method. Here, the problem is not seen as one of examining the viability of a given size population in terms of the number of jobs available to support that population. Rather it is assumed that development potential exists and that the constraining factor on growth will be the supply of developable land. The projection process moves, therefore, from land availability to assumptions about the density and mix of residential development to multipliers for population based on the number, type, and size of units.

Methods of Projecting Population with the Presence of a Refinery.

Projection of the demographic impact in the presence of a proposed refinery has to be based directly on an estimation of the employment impacts due to the proposed refinery. This section will be divided, therefore, into three subsections: The first deals with construction worker impacts, the second with operating worker impacts, and the third with impacts due to nonbasic employment. In each case there are good primary data on family characteristics of the relevant populations of workers. The essential issue is the extent to which the work force will be made up of existing residents of the area as opposed to requiring inmigration of workers into the area. Analysis of this issue for the construction worker population was already examined in the Economic section. Here it will be necessary to examine the demographic implications of construction worker migration and to explore the more difficult case of the operation and the nonbasic workers.

The extent to which nonlocal workers will be required depends principally on the skill levels and availability of labor on the one hand relative to the occupational mix and level of labor demand on the other. What makes the issue more difficult is that the time period for which labor market conditions have to be evaluated is likely to be several years in the future. Without a cohort-survival model to keep track of the size of the projected labor force and explicit employment projections to estimate the demand for labor, it is difficult to do more than make an informed conjecture about what the supply/demand balance may be at some future time.

Construction Worker Demographic Impacts

Because the local/nonlocal mix of the construction workforce affects the size of the economic mulipliers, the considerations relevant to its determination where discussed in the preceding Economic section. Study area population increases will only occur to the extent that the construction force is made up of nonlocals. Various case studies have found the total population influx per 100 nonlocal workers to vary significantly by region and type of facility. Therefore, as the project startup approaches and as more information becomes available, careful thought should be given to the reasonableness of the demographic assumptions utilized in the initial projections. The major variation occurs in the split between married workers with family present relative to those with family absent. Much of this variation may be able to be anticipated by the planner based on the availability of housing in the study area.

Operation Worker Demographic Impacts

The local/nonlocal composition of the operating period workforce can be dealt with in the following way.

First, consider the nature of the jobs. Some percent of the jobs may be sufficiently technical that workers are sure not to be available locally. If so, these workers can be assigned as nonlocals. The remaining jobs would presumably be accessible to locals depending on supply/demand conditions in the local labor market.

Second, if a community has been growing steadily and there is no compensating reduction in basic employment, then most of the remaining operation workers would have to be nonlocal. If the community has not been growing rapidly, then some of the increase will come from new entrants to the labor force, some from the unemployed, and some from other jobs.* Neverthless, the operation jobs tend to be very attractive in the local

* To the extent that they do come from other jobs, nonlocal workers may move in to take the original job so there may still be a positive effect on population.

labor market and a 50 percent local ratio for the operation workforce that is not too large relative to the area of the activity seems reasonable (although this percentage is likely to fluctuate with respect to the size and type of community/county).

Nonbasic Worker Demographic Impacts

The local/nonlocal mix of the employment induced by the construction and operating period employment will be influenced by the same factors discussed above in the context of the local/nonlocal mix of the operating force. If the local economy has been growing and if job opportunities have been sufficiently available so that labor force participation rates have been increasing, then nonlocals are likely to be required to meet the increase in nonbasic employment.

In the examples worked out for the hypothetically proposed refinery in the Economic subsection of Section 3.9.5.1, increases in nonbasic employment were estimated based on the principle of sustainable nonbasic employment growth. The estimated increase in the example was on the order of 950 to 1150 during the construction period and around 680 nonbasic jobs during the operations period. An adjustment will have to be made, however, because a significant percent of these jobs will end up being held by additional workers in families already present in the area. The suggestion here, therefore, is that if local labor market conditions are assumed to be tight, (i.e., the unemployment rate is low and employment has been increasing) one nonlocal male may be assumed to inmigrate for each two nonbasic jobs available.[55] This assumes that the second nonbasic job will be taken by other labor force entrants already in the area or who have accompanied new inmigrants to the area.

Summary of Demographic Impact Methods

The analysis of demographic impacts of a proposed refinery always requires three major conceptual steps. First, it is necessary to calculate the total employment increase, both basic and nonbasic, associated with the proposed refinery. Second, assumptions have to be made with respect to the local/nonlocal composition of the workers that will fill the new jobs. Third, demographic characteristics have to be ascribed to the nonlocal workers and their families so that the total change in the size and structure of the population can be calculated. The purpose of the discussion in the preceding sections has been to explain some of the different ways in which each of these conceptual steps can be approached.

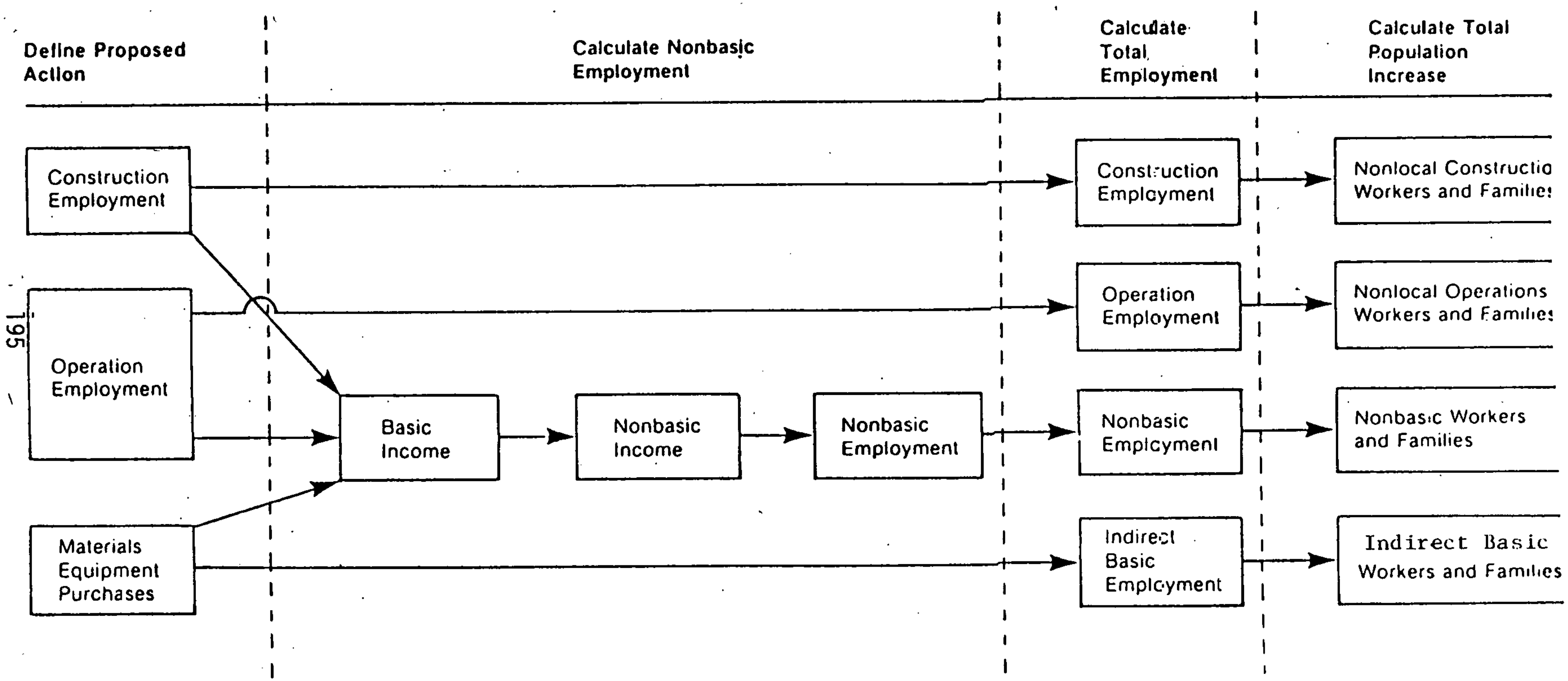
As part of the discussion of methodological alternatives, a framework has been constructed which illustrates how an economic base type approach could be combined with assumptions about local/nonlocal composition and about demographic characteristics to study the demographic implications of a proposed refinery. This example should be firmly based on (1) empirical data, (2) judgment of the analyst (local government), and (3) the specific conditions of the particulate planning problem; therefore, since there are subjective decisions to be made with the approach, only the procedure for performing this process is presented here. The discussion above has made it clear that the effects of a specific project in a specific area will be unique to that set of circumstances. The purpose of this guide is to focus attention on the key issues that determine the size of these effects so that the planner can apply his/her own judgment on a case-by-case basis.

Figure 44 shows the conceptual steps followed in the process of analyzing the impacts of a proposed refinery.

If actual numbers were utilized then they would be based on the following considerations:

- amount of basic income generated,
- size of the income multiplier,
- local/nonlocal composition of both the construction force and the operations force,
- marital status and family size of the construction, operation and nonbasic workers,
- sustainable growth in nonbasic employment, and
- the extent to which nonbasic jobs will be assumed by other family members of construction, operations or nonbasic employees.

FIGURE 44 CONCEPTUAL STEPS FOLLOWED IN TRACING THROUGH THE DEMOGRAPHIC IMPACTS OF A PROPOSED REFINERY



Source: Reference 36

These considerations together with the assumptions which would be made in the Economic section, determine the total population influx associated with the construction peak year and an operation period year. This population influx can be organized into an interacting framework which is shown in Figure 45.

It must be emphasized that the purpose of working through Figure 45 shows the variables that are the important determinants of the magnitude of impacts. The actual results depend on the particulate assumptions made. Two that are particulately important are the local/nonlocal breakdown of the construction force and the amount of nonbasic employment that will actually occur during the construction period.

Other Approaches to Demographic Impact Analysis

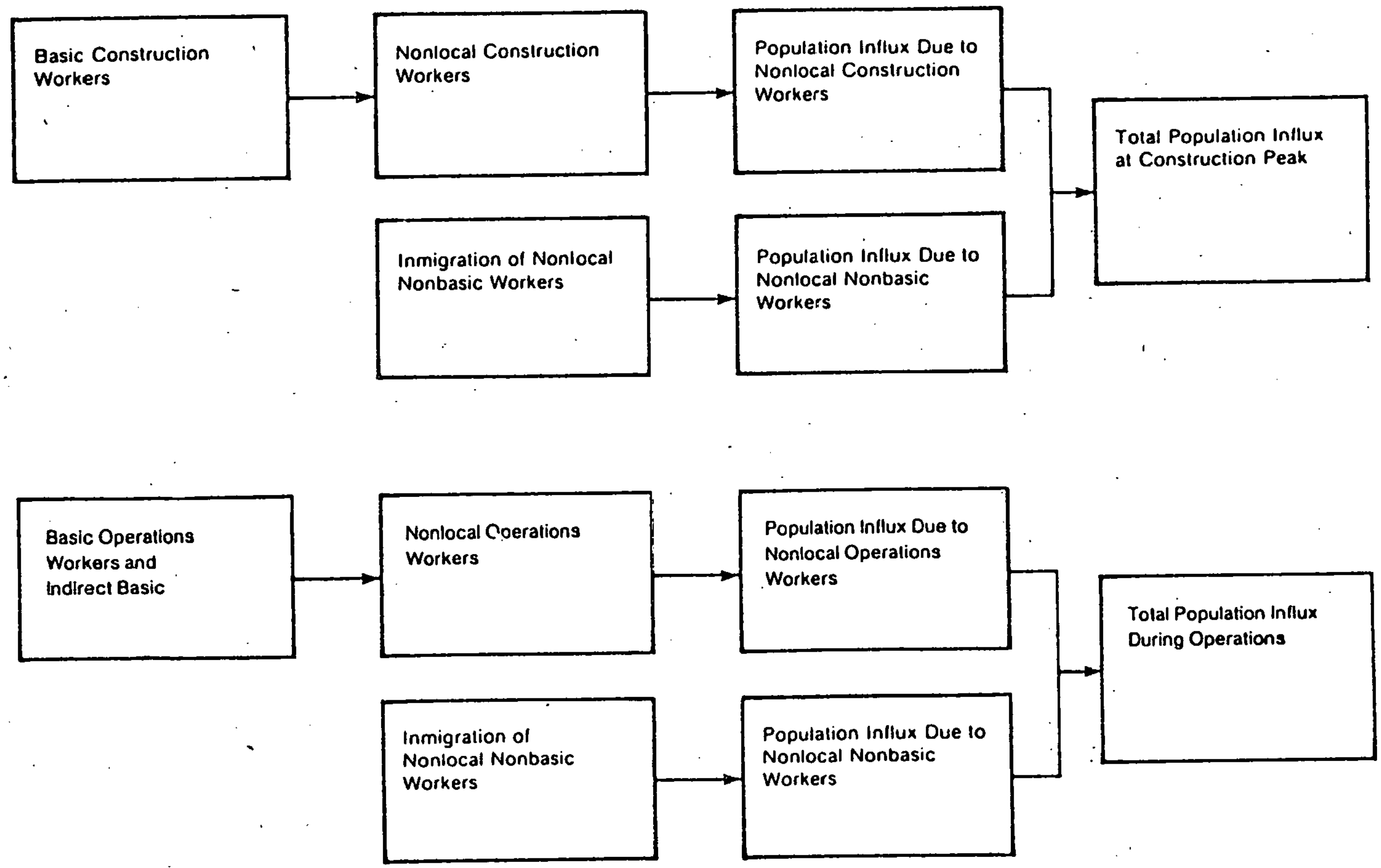
One inescapable conclusion from working through reviewing the last example is that there are many parts of the economic/demographic assessment process that are both complicated and subject to uncertainty. As a result, it is not surprising that attempts have been made to come up with simpler procedures that will give usable results. Two of these methods are reviewed here. The first is summarized in Figure 46 which was prepared by David Williams for HUD inpact guide entitled Rapid Growth from Energy Projects.[53]

The notable assumptions he made are:

- all construction and operation workers nonlocal,
- employment multiplier constant at 1.6 during construction,
- employment multiplier constant at 2.5 during operation,
- all potential nonbasic employment occurs with 80 percent of the workers coming from in-migrants who out-migrate after the peak.

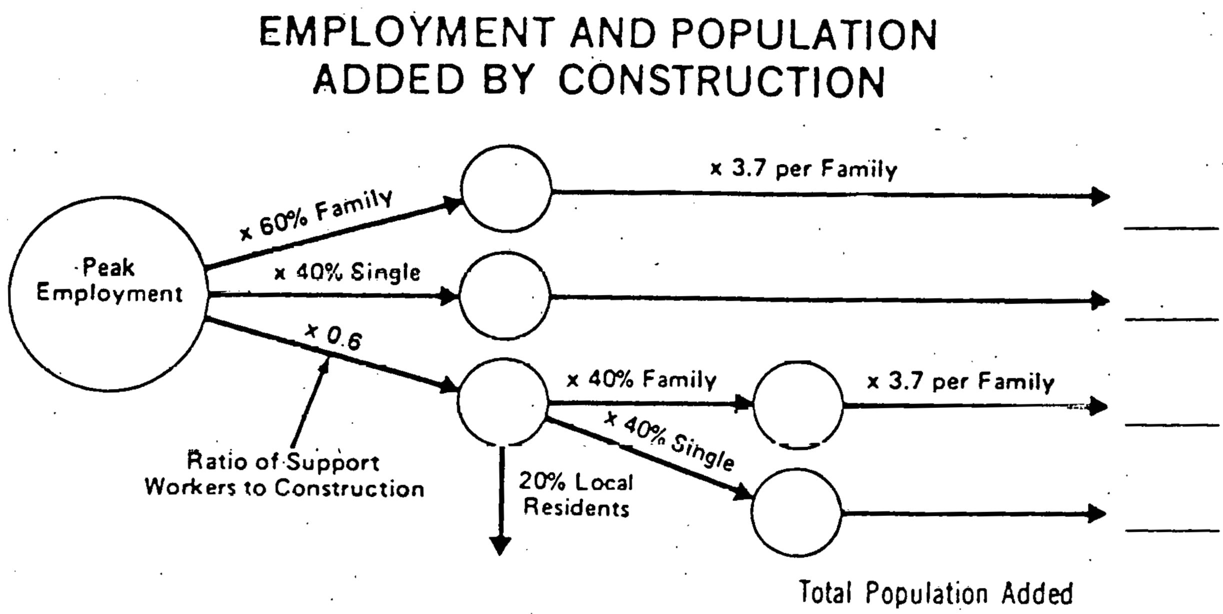
(In the guide, the example included unemployment and population figures for the construction and operation of a 2250 MW Coal-Fired Electric Power Plant. For our purposes, the numbers have been removed.)

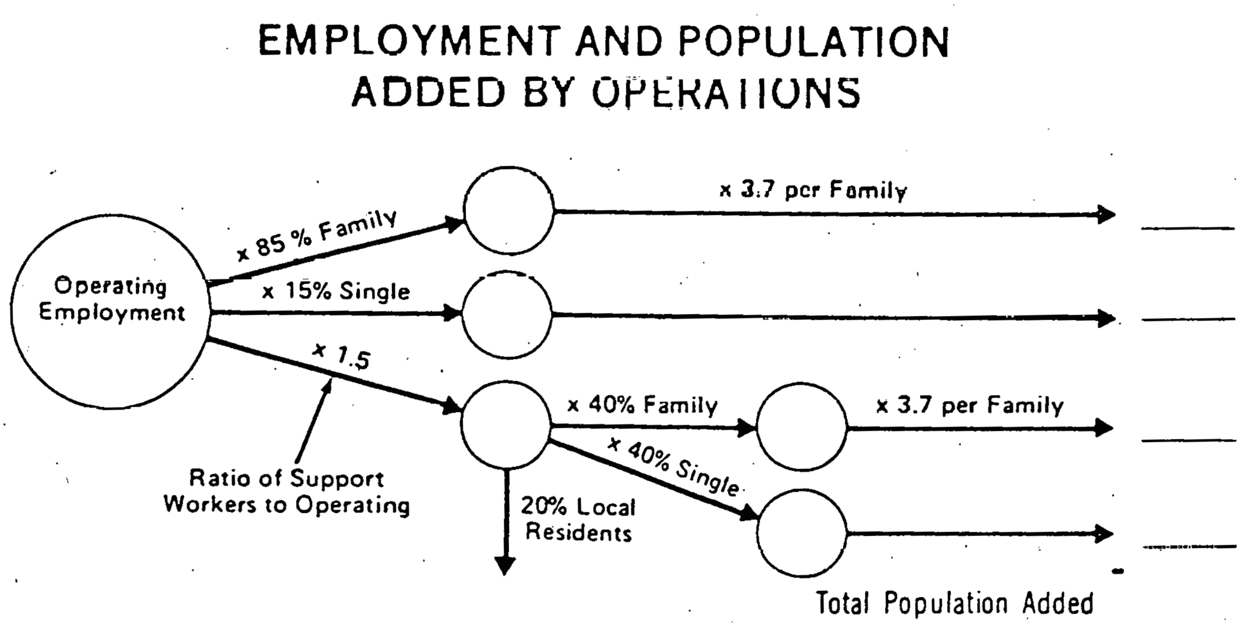
FIGURE 45 SUMMARY CALCULATION FRAMEWORK OF POPULATION INFLUX DUE TO PROPOSED REFINERY



Source: Reference 36

FIGURE 46 EMPLOYMENT AND POPULATION IMPACTS AS ESTIMATED IN THE HUD GUIDE





Source: Reference 53

FIGURE 47 EMPLOYMENT AND POPULATION IMPACTS AS ESTIMATED IN EPA ACTION HANDBOOK

1. Peak construction year population impact

Peak construction workers times percent single (.25).

_____ x .25 = _____

Peak construction workers times percent married (.75) times average family size (3.6)

_____ x .75 x 3.6 = _____

Peak construction workers times construction worker to service worker ratio (.6) times percent single service workers (.15).

_____ x .6 x .15 = _____

Peak construction workers times construction worker ratio (.6) times percent married service workers (.85) times average family size (3.6).

_____ x .6 x .85 x 3.6 = _____

Total population influx equals a + b + c + d.

_____ + _____ + _____ + _____ = _____

2. Operations year population impacts

Operating and indirect basic workforce times percent single (.15).

_____ x .15 = _____

Operating and indirect basic workforce times percent married (.85) times average family size.

_____ x .85 x 3.7 = _____

Operating and indirect basic workforce times service worker to operating worker ratio (1.5) times percent single service workers (0.15).

_____ x 1.5 x .15 = _____

Operating and indirect basic workforce times service workers to operating worker ratio (1.5) times percent married service workers (.85) times average family size (3.7).

_____ x 1.5 x .85 x 3.7 = _____

Total Population influx equals a + b + c + d.

_____ + _____ + _____ + _____ = _____

Source: Reference 54

A similar approach is outlined in the Action Handbook: Managing Growth in the Small Community[54] prepared by Briscoe, Maphis, Murray and Lamont, Inc. for the U.S. Environmental Protection Agency. They suggest a fill-in-the-blank approach which results in the calculation shown in Figure 47.

The key assumptions on which the Action Handbook recommendations are based include the following:

- All construction and operation workers are nonlocal.

- The employment multiplier is constant at 1.6 during the construction period and 2.5 during the operation period (derived from the HUD Guide).

- 75 percent of construction workers are married and they all bring their families with them. (This is attributed to the Construction Worker Profile,[79] but this source shows that for the average of 14 projects surveyed there were only 48.9 percent of nonlocal workers married with family present).

- All potential nonbasic employment actually occurs and 100 percent of the required nonbasic workers are nonlocal and immigrate to the area.

Comparison of the assumptions in the Action Handbook and the HUD Guide with those made by means of the income multiplier will all generate different answers. A range of peak construction and operation workforce estimates and population can be constructed to exhibit a significantly large differential. Consequently, since each method utilizes different assumptions and a range of projection results, the application of one of these methods to a site-specific planning study should be preceded by an analysis of the respective assumptions with regard to the community and facility characteristics. From this basis, it is possible to choose the method which most closely exemplifies the local demographic and economic profile of the workforce, population, and intrastructure.

Impact Analysis

Population projections must be analyzed relative to the following criteria. Such analysis will provide comprehensive evaluation of the local demographic assessment.

Were baseline demographic projections established without the proposed refinery? Were the projections related to a realistic analysis of changes in the economic base of the area?

Was thought given to the economic feasibility of the projected expansion in nonbasic employment?

Was the local/nonlocal composition of the required construction, operation, and nonbasic workforce analyzed in light of projected conditions of supply and demand in local labor markets?

Were allowances made for secondary labor force entrants accompanyi inmigrating families?

3.9.4.3 Facilities and Services

Questions/Issues

The purpose of analyzing facilities and services demand is to anticipate the demand for facilities and services associated with the proposed refinery. Conditions projected to accompany the proposed refinery compared with the situation that would exist without the proposed refinery provides a measure of the impact of the proposed refinery on services and facilities. The principal questions that have to be dealt with are:

What will be the quality and the extent of utilization of facilities and services in the absence of the proposed refinery?

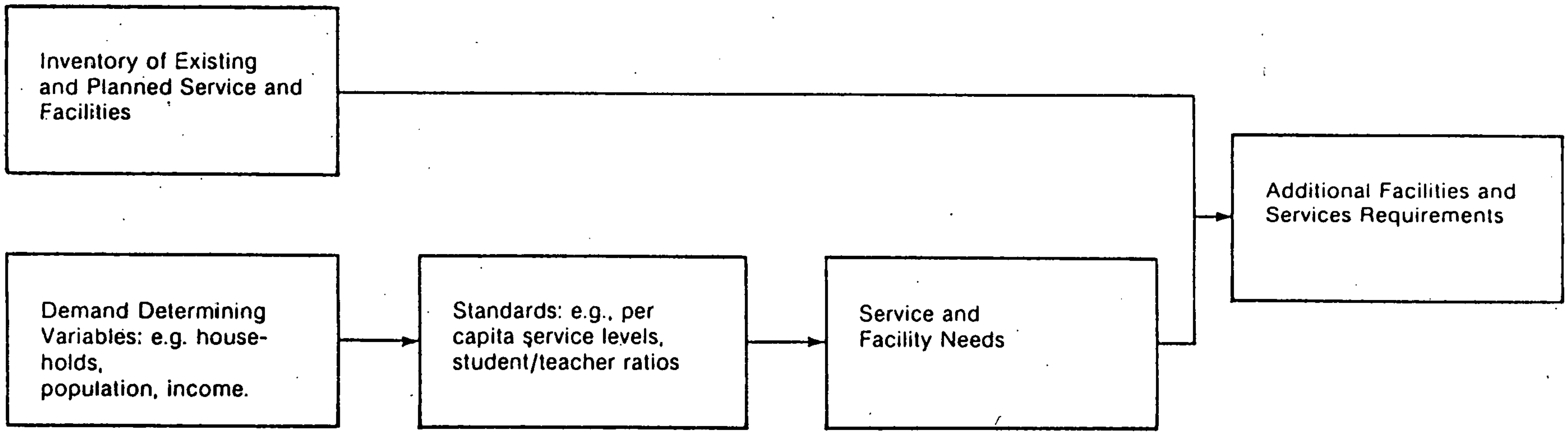
What will be the changes in services and facilities demands associated with the employment, income, and population generated by the proposed refinery?

In light of the answers to the first two questions, what new facilities will have to be built and what new services will have to be provided?

In order to answer the questions and issues, data must be collected which addresses both the supply of the facilities and services and the local demand for these items, both currently and in the future. Derivation of the supply data is relatively straight forward and essentially involves compilation of an inventory of the existing facilities and services and an evaluation of current plans for expansion, potential for expansion, and physical limitations to expansion.

Obtaining the required data concerning demand is somewhat more involved. The demand data is derived from assessing those variables that are the principal determinants of the facility or service demands, e.g., school age children in the case of educational facilities and services, or households in the case of housing demand. These variables, sometimes referred to as "driving" variables, are generated in the economic and the demographic analyses described in the preceding two sections. The third type of information required is a set of "standards" that translates the value of the driving variables into a level of demand for a facility or service. It is important to recognize that the term "standards" is used in the most general sense here to include legislatively imposed conditions that must be complied with (e.g., wastewater treatment requirements), historically observed levels of service or facility provision, or some locally desired level of infrastructure that has not been attained historically but that represents the community's aspiration. The combination of the driving variables and the standards determine demand which can then be contrasted to supply to determine requirements as shown in Figure 48.

FIGURE 48 PRINCIPAL STEPS IN THE ANALYSIS OF FACILITIES AND SERVICES REQUIREMENTS



Source: Reference 36

A considerable amount of material is available on each of the major service and facility areas.* The purpose here, therefore, is only to provide a guide to the analysis of each of the major functional service or facility areas.

The following list of facilities and services identify the data required to perform an analysis of the existing facilities and services and determine if they are adequate to satisfy the demands of the projected future population both with and without the refinery. In addition to identification of the necessary data for the evaluation, the tables also indicate (1) the possible sources of this information; (2) the key variables influencing the demand for that service; and (3) the standards established for the operation of each respective component.

HOUSING

Existing Facilities

Type of Information
- number of units by type of unit
- vacancy rates by type of unit
- conditions of units
- price of units

Source of Information

Economic Practices Manual[62] has a useful chapter on housing market analysis

Additional information is in FHA Techniques of Housing Market Analysis, U.S. Dept. of Housing and Urban Development, Washington, D.C.

Decennial Census

Local mortgage lending institutions (Savings and Loans, Commercial Banks)

Primary data survey or aerial photography

County Assessor's Office

*References 55-62

Projection of Impact

Driving Variables

Number of nonlocal construction workers -- the best data on actual distribution of housing types by non-local construction workers is from a combination of survey data from Bureau of Reclamation and Corps of Engineers Projects. The data are summarized in an appendix to: Chief Joseph Dam, Community Impact Report Update III, Conditions at Peak Impact. From these data, the estimated distribution is 20 percent single family, 15 percent multifamily, 40 percent mobile home and 25 percent temporary including travel trailer, camper or sleeping room.

Number of households associated with population influx of nonlocal operations workers and nonlocal nonbasic workers -- can be estimated as number of nonlocal male operations workers plus number of nonlocal male nonbasic workers. Estimated distribution of type of unit is 50 percent single family, 15 percent multifamily, 35 percent mobile home.[79]

HEALTH

Existing Facilities

Type of Information

service area population

patient days per year at hospitals

number of beds and sizes of professional staff at hospital

number of doctors, dentists and registered nurses in the community

mental health facilities

ambulance service

nursing home facilities

service area population able to be adequately served by existing health care personnel and facilities

plans for expansion

Source of Information

hospital administrator

state and local government health service administrators

Projection of Impact

Driving Variables

population by age and sex

Standards

4 to 4.5 beds per 1,000 population.[59]

A recommended minimum number of health practitioners is one doctor for every 1,000 persons. In small communities, general practitioners will be most common; there should be few specialists -- a cardiologist, an anesthesiologist, a pathologist, an internist, and so forth -- practicing at the area's hospital.

To calculate hospital bed needs, the following formula is widely used.[60]

A. Current Use Rate:

$$\frac{\text{Patient Days Per Year}}{\text{Current Population}} = \text{Current use rate}$$

B. Average Bed Need:

$$\frac{\text{Current Use Rate x Projected Population}}{365} = \text{average bed need per day}$$

C. Bed Need:

$$\frac{\text{Average Bed Need Per Day}}{\text{.80 (occupancy rate)}} = \text{bed need (for projection year)}$$

There should be about 0.5 dentists per 1,000 population -- about half the number of doctors usually recommended. There should probably be at least one oral surgeon practicing at the area's hospital (this is common only in relatively rural areas; in larger cities, it is feasible for oral surgeons to have private offices).

Registered nurses should average 8 per 1,000 and health support personnel 2.5 per 1,000.[55]

EDUCATION

Existing Facilities

Type of Information

- service area population
- current enrollment
- number of classrooms (elementary, junior high, senior high)
- number of teachers
- number of schools and sizes of sites
- conditions of buildings
- description of institutions of higher education
- school transportation system
- service area population able to be served by existing facilities and staff
- plans for expansion
- indebtedness and fiscal condition of school district

Source of Information

- local school administrators
- state departments of education

Projection of Impact

Driving Variables

population aged 5-11, 12-14, and 15-17

Enrollment as a proportion of school age population can be derived from census data. Usually about .90.

Standards[59]

A commonly used maximum student/teacher ratio is 30 to 1 for elementary schools. There should be a classroom or its equivalent for each teacher in the school.

An elementary school should provide 90 square feet per pupil. This includes teaching and administrative space, libraries, gymnasiums, and so forth. The recommended radius of the service areas for elementary schools is one-half mile. However, in sparsely populated areas, this is rarely practical. Some very small towns have no schools at all and students must be bused to towns with schools. The recommended minimum size for elementary schools is 250 pupils. H wever, in small, isolated communities, it is sometimes necessary to provide elementary schools for as few as 25 students. The minimum size for an elementary school site is recommended to be 6 or 7 acres. Recreation facilities, such as playfields, playground equipment, basketball courts, baseball diamonds, and so forth, should be provided at elementary schools.

In larger elementary schools there is an administrative staff much like that for secondary schools, including principals, librarians, and counselors. The U.S. Department of Health, Education and Welfare published statistics showing that one staff member will be needed for every eight teachers. For small elementary schools, there is usually a principal only, and in very small schools, there may be only a half-time principal -- sometimes called a teaching principal. This is often an adequate and practical arrangement.

A frequently used maximum student-teacher ratio for secondary schools is 27 to 1. A classroom or its equivalent should be provided for each teacher. In secondary schools, 150 square feet per pupil should be provided. The usual minimum size recommended for secondary school sites is 32 acres; the average size is 40 acres.

The recommended radius of the service area for secondary schools is about 1-1/2 miles. For sparsely settled areas, such a standard is unrealistic. High schools are usually located in an area's larger towns and students are bused from surrounding areas. A minimum recommended size for secondary schools is 1,000 students, but there are cases when it is necessary or economically advantageous to provide secondary schools for student bodies of only a few hundred.

In secondary schools, one administrative staff member is needed for every eight teachers.

POLICE

Existing Facilities

Type of Information

service area population

number of policemen

number of vehicles

office space (square feet)

service area population able to be adequately served by existing personnel and equipment

Source of Information

local police chief and county sheriff

Projection of Impact

Driving Variables

population

Standards[57,59]

Typical standards for small communities in the western U.S. call for between 1.4 to 3 police officers per 1,000 population.

Standards for patrol cars vary from one for each patrolman to one for every three. The actual number needed will depend on the town's particular needs and the number of shifts operated.

For towns with populations up to 30,000, one central police station is generally adequate. For larger towns, branch stations may be necessary. About 200 square feet of office space is needed for each patrolman. Central dispatcher facilities are needed for towns of 5,000 to 10,000 or more.

Very small communities (1,000 persons or less) and rural areas are usually served by the county sheriff's department. Some small towns, feeling the need for local police, hire a town marshal..

FIRE

Existing Facilities

Type of Information

service area population

type of department (volunteer or permanent and number of firemen)

rating of fire department

equipment

capacity of water system and pumping capacity of equipment

fire department building space (square feet)

service area population able to be adequately served by existing personnel and equipment

plans for expansion

Source of Information

fire chief

Projection of Impact

Driving Variables

dwelling units, preferably by type of construction

density

Standards[59]

The table below shows typical fire flow requirements for various levels of population.

The minimum state size usually recommended is about 5,000 square feet. Each station should serve an area within a two-to-six mile radius although this may vary depending on the area's needs.

For small towns (up to 30,000 people), two pumpers, a staff car, and an ambulance are considered adequate basic equipment. For very small communities (under 1,000 population), one pumper may be adequate. About 20 volunteer firemen would be an adequate number to operate one pumper.

Volunteer fire departments are usually adequate for towns smaller than 10,000 persons, as long as there are enough volunteers to operate the necessary fire equipment. Two full-time firemen per 1,000 dwelling units should be employed in larger communities (10,000 and larger). For major cities, five firemen per 1,000 dwellings are recommended

REQUIRED FIRE FLOW BY POPULATION[61]

Population	gpm	mgd	Duration, hours
1,000	1,000	1.44	4
1,500	1,250	1.80	5
2,000	1,500	2.16	6
3,000	1,750	2.52	7
4,000	2,000	2.88	8
5,000	2,250	3.24	9
6,000	2,500	3.60	10
10,000	3,000	4.32	10
13,000	3,500	5.04	10
17,000	4,000	5.76	10
22,000	4,500	6.48	10
27,000	5,000	7.20	10
33,000	5,500	7.92	10
40,000	6,000	8.64	10
55,000	7,000	10.10	10
75,000	8,000	11.50	10
95,000	9,000	13.00	10
120,000	10,000	14.40	10
150,000	11,000	15.80	10
200,000	12,000	17.30	10

NOTE: Over 200,000 population, 12,000 gpm, with 2,000 to 8,000 gpm additional for a second fire, for a 10-hour duration.
gpm = gallon per minute
mgd = millions of gallons per day

TRANSPORTATION

Existing Facilities

Type of Information

elements of the system: by administrative unit, (municipal, county, state, federal) and by mode (air, rail highways)

current level of service: volume, congestion, accident rates

plans for expansion

Source of Information

city engineer or municipal streets department

county commissioners

state and federal highway departments

airport or special transportation district administration

Projection of Impact

Driving Variables

dwelling units by type

population

Standards

Transportation planning is a large and complicated subject. There are two recently published approaches to the estimation of road and street requirements of development that would be applicable to some impact analysis.

Murphy/Williams suggests a methodology originally developed for the Council on Environmental Quality in Costs of Sprawl (1974). The system requires residential-related street system requirements based on number of residental units and then uses the residential-related requirements to estimate community street system requirements.

Residential-Related (Linear Requirement)

arterials (100 ft. ROW) = SFU x 6 ft/unit + MH x 5.5 ft/unit + MFU x 5 ft/unit

collectors (60 ft ROW) = SFU x 7 ft/unit + MH x 17.25 ft/unit + MFU x 13.5 ft/unit

minor streets (50 ft ROW) = SFU x 47 ft/unit + MH x 22 ft/unit + MFU x 10 ft/unit

Where ROW denotes right-of-way, SFU denotes single family unit, MH denotes mobile home and MFU denotes multi-family unit.

Cmmmunity (Lineal Requirements)

arterials = residential related arterials x 1.76

collectors = residential related collectors x 1.1

Minor Streets = residential related minor streets x 1.1

NOTE: Action Handbook: Managing Growth in the Small Community[54] (p. 71), suggest that .04 linear miles of streets (60 ft ROW) be assumed per acre of land developed. This implies land requirements of .3 acres for streets for each 1 acre developed.

Standards and planning criteria for railroads and airports are in Planning Design Criteria[60] (p. 97). This volume also contains a significant amount of information on street, roads and parking design and on subdivision planning requirements.

The Manual of Housing/Planning and Design Criteria[61] (p. 97), contains more information on the street and parking implications of residential development.

WATER

Existing Facilities

Types of Information

service area population

peak and average daily usage: gallons per day

water supply: acre-feet/year by source

water treatment plant capacity: gallons per day

water distribution capacity: gallons per day

storage capacity: gallons

conditions of facilities

service area population able to be adequately served by existing supply, treatment facilities, storage facilities, and distribution system

plan for expansion

relevant state or local standards for supply, treatment, storage, and distribution

does water meet U.S. Public Health Service Standards and other relevant state or local standards

Sources of Information

city engineer

county health department

state health department

Environmental Protection Agency

Projection of Impact

Driving Variables

dwelling units

population

Standards[59]

A water supply standard of .20 acre feet per person per year or 150 gallons per day per capita is often used.

Water supply for small outlying communities usually comes from springs or wells. The standard for adequate stream or well flow is 1,600 gallons per day per connection. This is based on an estimate of about 450 gallons per day per capita peak usage.

When a town's water is supplied through a reservoir, the supply figure, normally expressed in acre feet, is based on average water usage. In this case, the limiting factor is the amount of water which can be treated in a day. When a town's water is supplied through wells and springs, the limiting factor is the amount of water which can be provided by these sources in a day. Treatment for well and spring water usually consists only of chlorination; sometimes no treatment is needed.

NORMAL WATER CONSUMPTION (gallons per day)[59]

Class	Normal Range	Average
Domestic use	15-70	50
Commercial, industrial use	10-100	60
Public use	5-20	10
Miscellaneous Use	10-40	25
TOTAL	40-230	150

NOTE: Water treatment plants should be able to process enough water to meet the service population's peak usage plus 15 percent. The size and amount of pipe needed for water distribution will depend primarily on housing density.

WASTEWATER

Existing Facilities

Type of Information

service area population

peak and average daily usage: gallons per day

treatment capacity: gallons per day

collection system capacity: gallons per day

condition of collection system

service area population able to be adequately served by existing treatment and collection systems

plans for expansion

relevant federal, state or local standards

does treatment meet relevant standards

Source of Information

city engineer

county health department

state health department

Environmental Protection Agency

Projection of Impact

Driving Variables

dwelling units

population

commercial, industrial or public sector

Standards[59]

Most small developments in rural areas do not require wastewater treatment if the soils are suitable for septic tanks and if the systems are properly maintained.

Where soils are inadequate or in more densely populated areas, a central wastewater treatment system should be built. For small communities, or groups of small communities, a secondary lagoon or series of lagoons is generally considered adequate. This type of system requires little maintenance and is practical where land is readily available and inexpensive. It is not as effective as some other secondary treatment systems, however. For determining lagoon sizes, about 10 acres per 1,000 people is considered average.

For larger towns, more effective secondary or tertiary treatment may be necessary. A general standard for determining sewage treatment plant capacity is that a peak of about 168 gallons per day is generated per person.

NORMAL WATER CONSUMPTION (gallons perperson per day)[65]

Class	Normal Range	Average
Domestic	15-70	50
Commercial, industrial	10-100	65
Public	5-20	10
Miscellaneous	10-40	25
TOTAL	40-230	150

The table below shows the sewage generation rates for commercial and public establishments.

SEWAGE GENERATION RATES FOR COMMERCIAL AND PUBLIC ESTABLISHMENTS[59]

	Gallons/Person/Day
Hotels	50 to 150
Motels	50 to 125
Restaurants (toilet and kitchen wastes per patron)	7 to 10
Additional for bars and cocktail lounges	2
Tourist courts with individual bath units	50 to 120
Luxury camps	100 to 150
Camps	25 to 40
Day Camps (no Meals)	15
Day schools (with cafeterias, showers)	15 to 25
Boarding schools	75 to 100
Day workers at schools or offices	12 to 35
Hospitals	150 to 250 or more
Factory workers (per shift)	15 to 35
Picnic parks (with bathhouses and showers)	10
Swimming pools and bathhouses	10
Drive-in theaters (per car space)	5 to 10

Theaters (per seat)	5
Places of assembly	3 to 10
Airports (per passenger)	3 to 5
Self-service laundries (per wash)	50
Stores (per toilet room)	400
Service Stations (per vehicle served)	10

	Gallons/Day 1000 sq. ft
Hotels	600 to 1,100
Office Buildings	100 to 500
Department Stores	100 to 400
Apartment Hotels	200 to 400

	Gallons/Day/Acre
Light Industry	14,000
Hotels, Stores and Office Buildings	60,000
Markets, Warehouses, Wholesale Establishments	15,000
High-Cost Residential	7,500
Medium-Cost Residential	8,000
Low-Cost Residential	16,000

NOTE: A minimum capacity for most secondary or tertiary treatment plants is the ability to treat one million gallons per day.

A minimum number of employees needed to operate and maintain a secondary or tertiary treatment plant in a small community is considered to be 6.5 persons.

The total length of pipe for the sewage collection system depends on housing type and density.

SOLID WASTE

Existing Environment

Type of Information

service area population

current usage

capacity of disposal site (acres/year)

adequacy of collection equipment

service area population able to be adequately served by existing site and collection equipment

plans for expansion

relevant federal, state or local standards

does site meet relevant standards

Source of Information

city engineer
county health department
state health department
Environmental Protection Agency

Projection of Impact

Driving Variables

dwelling units
population
nature of commercial/industrial activity

Standards[59]

Standards for solid waste disposal sites vary from state to state, but most states now require sanitary landfill sites for all communities. It may sometimes be most practical for counties with several very small communities to establish a system of landfill sites which are shared by several communities.

Assuming that five pounds of waste per capita are generated each day, that the waste is compacted, that the fill depth is seven feet and that two-thirds of the site is covered by solid waste, approximately .21 acres per 1,000 persons is needed each year for sanitary landfill.

For solid waste collection in small communities, one collection vehicle serves about 3,000 dwelling units. So for each 1,000 units, 33 percent of one truck and 2,148 person-hours are needed per year.

PARKS AND RECREATION

Existing Environment

Types of Information

service area population

current usage

description of facilities

number of staff

service area population able to be adequately served

plans for expansion

Sources of Information

city and county departments of parks and recreation
state outdoor recreation coordination committee
Heritage, Conservation and Recreation Service

Projection of Impact

Driving Variables

population
characteristics of population
statutory requirements

Standards

Municipalities usually provide public recreation facilities for their residents in the forms of parks and playgrounds. The need for recreation and park space is related both to community type and density. For incorporated communities except central cities and suburbs, playgrounds serve an area within one-half mile, and neighborhood parks, an area within one mile. Outlying communities usually have community parks which should, ideally, serve an area within two miles. In urban areas with high population density, the same facilities serve smaller areas: 3.8 mile for playgrounds, 3/4 mile for neighborhood parks and 1-1/2 miles for community parks.

The amount of land in parks in towns of less than 10,000 population depends on donations of land, preferences of residents and the municipal budget.

RECREATION FACILITY AND PARK STANDARDS (TOWNS OF 1,000 to 25,000)

Population Served	No. Acres Playground	No. Acres Parks	No. Acres Sport Fields	Recreation Facilities Recommended
1,000	1/2	1-1/2	1-1/2	2 basketball courts
2,000	1	3	3	4 basketball courts 1 tennis court
3,000	1-1/2	4-1/2	4-1/2	6 basketball courts 1 tennis court 1 softball field
4,000	2	6	6	8 basketball courts 2 tennis courts 1 softball field
5,000	2-1/2	7-1/2	7-1/2	10 basketball courts 2 tennis courts 1 softball field 1 wading pool
6,000	3	9	9	12 basketball courts 3 tennis courts 2 softball fields 1 baseball field 1 wading pool
10,000	5	15	15	20 basketball courts 5 tennis courts 3 softball fields 1 baseball field 1 25-yd swimming pool 2 wading pools
15,000	7-1/2	21	21	28 basketball courts 7 tennis courts 5 softball fields 2 baseball fields 1 25-yd swimming pool 3 wading pools
20,000	10	30	30	40 basketball courts 10 tennis courts 6 softball fields 3 baseball fields 1 50-yd swimming pool 4 wading pools

Population Served	No.Acres Playgrounds[a]	No.Acres Parks[b]	No.Acres Sport Fields	Recreation Facilities Recommended
25,000	12-1/2	37-1/2	37-1/2	50 basketball courts 12 tennis courts 8 softball fields 4 baseball fields 1 50-yd pool(indoor/outdoor) 5 wading pools 1 golf course(9 or 18 hole) 1 football field 1 community center

NOTE: [a]It is assumed that some playground equipment, e.g. swings, will be provided.
[b]It is assumed that picnic tables will be provided in parks.
[c]For larger communities, the standards for playgrounds and park sizes are shown below.

PLAYGROUND AND PARK SIZE STANDARDS (CITIES OF 30,000 OR LARGER)[59]

Type of City	Playground Size (per 1000 d.u.)	Neighborhood Park Size (per 1000 d.u.)	Community Park (per 1000 d.u.)*
Central City (30,000 or more population)	20.0 acres	1.7 acres	2.5 acres
Mature Suburb (30,000-100,000 population)	2.5 acres	2.1 acres	3.1 acres
Mature Suburb (100,000 or more population)	2.3 acres	1.9 acres	2.9 acres
Suburb (30,000-100,000 population	2.1 acres	1.8 acres	2.7 acres

*d.u. = dwelling unit

The size of the park maintenance staff depends largely on the size of the area to be maintained and the climate (areas with cold winters usually need less recreational maintenance staff in the winter than do areas where the weather is warm all year). In very small communities with little park land, only part-time maintenance may be required.

For towns of 10,000 to 30,000 population, from 0.3 to 0.45 full-time workers per 1,000 population are needed. For towns of 30,000 to 100,000 recreation employment requirements range from 0.5 to 0.6 full-time workers per 1,000 population and 2.4 part-time workers per 1,000 population. For cities larger than 100,000 population 0.6 to 1.0 full-time workers per 1,000 are needed along with 1.5 part-time workers per thousand.

LIBRARY

Existing Environment

Types of Information

service area population

current usage

number of buildings and amount of space (square feet)

number of volumes and periodicals

linear feet of shelving

other library services (film lending, bookmobile, etc.)

service area population able to be served adequately by existing facilities and staff

plans for expansion

Sources of Information

Local librarian

Projection of Impact

Driving Variables

Population

Standards

The following table sets forth standards approved by the Public Library Association for small libraries:

GUIDELINES FOR SMALL LIBRARIES[62]

Population	Size of Book Collection	Total Floor Space
Under 2,500	10,000 volumes	2,000 square feet
2,500-4,999	10,000 volumes plus 3 books per capita for population over 3,500	2,500 square feet of 0.7 sq ft per capita, whichever is greater
5,000-9,999	15,000 volumes plus 2 books per capita for population over 5,000	3,500 square feet or 0.7 sq ft per capita, whichever is greater
25,000-49,999	50,000 volumes plus 2 books per capita for population over 25,000	15,000 sq ft or 0.6 ft per capita, whichever is greater

GENERAL GOVERNMENT

Existing Environment

Types of Information

description of government organizational structure

public administration personnel and facilities other than those identified in the preceding functional categories

service area population able to be served by existing facilities and staff

plans for expansion

Source of Information

local government officials

Census of Governments

Projection of Impact

Driving Variables

population

Standards

The level of local governmental service is determined by the services demanded by the government's constituents and by the authority granted by the state government. In very small towns (1,500 persons or less), there is frequently no paid staff at all; all necessary government work is done by volunteers. In towns up to 5,000, there may be only a part-time clerk and a part-time mayor.

Standards for general government vary widely from state to state; therefore, it is recommended that the state averages for services and employment for towns of approximately the size of the subject town be determined. Comparisons can then be made and adequacy assessed.

3.9.4.4 Land Use

Questions/Issues

As the impact assessment process continues from economic to land use analysis, the assessment process becomes increasingly closely tied to the planning process and the questions and issues begin to change in their emphasis from what will happen to how will it happen. The issues that arise in land use impact analysis are of four basic types:

What are the direct and indirect land use requirements of the proposed refinery?

What is the comparibility of the projected requirements with existing physical conditions - both natural and man-made?

What is the compatibility of the projected requirements with the expressed wishes and intentions of the local citizens?

What mechanisms exist by which to influence or control actual land development associated with the proposed refinery in a manner that respects local desires and that takes full account of existing physical conditions?

General guidelines are presented below to help deal with these issues. In the course of examining ways in which to describe the existing environment and to project impact, frequent references are made to certain key sources of additional information.[54, 60, 63]

Existing Environment

The first step in the land use assessment is to define the study area which is appropriate for the size of the project and which includes the area within which all, or the most significant, potential land use impacts will occur. In addition, mapping requirements of other human and natural environmental studies should be considered.

Following the delineation of study boundaries, base map(s) should be developed. These maps serve as the point of reference for all subsequent mapping and overlay materials. Furthermore, the maps should include basic topographic and man-made features, such as roads, structures, and jurisdictional boundaries and be accompanied by a written description of the area.

It is suggested in the <u>Rural and Small Town Planning Manual</u> that a classification system for existing areal land uses might include:

residential
commercial
industrial
public
agricultural
recreation
forest
open land
surface water

<u>Urban Planning and Design Criteria</u> suggests additional subclassifications that may be relevant for more urbanized areas when land use patterns are more complex.

The basic requirement in developing a land use classification scheme is that it be appropriate to the study area. This means that important local uses be distinguished, but that no more detail be introduced than is necessary.

In addition to areal land uses, linear land uses should also be mapped. These would include:

streets and highways
railroads
canals
transmission lines
pipelines
utility or municipal rights-of-way

Projection of Impact

Projection of land use impacts, as with the other steps in the assessment process, requires that projections without the proposed refinery be compared to projections with the proposed refinery. In both cases, in order for the land use projections to be plausible, they must be tied back to the economic and demographic projections.

Projections Land Use Requirements Without the Proposed Refinery

Projecting land use requirements in the absence of the proposed refinery requires use of the baseline economic and demographic and facilities/services projections that have already been discussed in the previous sections. If explicit population and facility services estimates have been made, it will be possible to make equally specific assumptions about land required for residential and commercial uses and for the sites for new facilities. If the baseline projections are built around a more general extrapolation of trends, it may be possible to deal with projected land use in the same general way. In cases where there is little or no growth in the baseline projections, this is definitely the case. In cases where commercial, industrial, and residential land uses are expanding, the situation will be more complicated and specific consideration will have to be given to underlying land requirements, to potential development areas, and to the expressed wishes of local residents with respect to the development plan of the community.

The implication of the above is that the ideal situation for the consideration of the impact of a proposed refinery is one in which a careful land use plan has already been done which realistically reflects the physical conditions that shape the development options of an area and also reflects the desires of the residents regarding which of the options they wish to pursue. If such a planning effort has not been undertaken, the propsect of planning for a large proposed refinery may serve as the catalyst to initiate the process.

Projected Land Use Requirements with the Proposed Refinery

Projecting land use requirements with the proposed refinery usually will be accomplished by estimating the direct and indirect requirements associated with the proposed refinery and then adding them to the baseline projections. The first step will require careful analysis of the direct land use requirements of the proposed refinery both during construction and operation periods. Consideration will have to be given to the construction site, to supply depots, and staging yards, to access roads and parking, and to auxiliary facilities for power generation, power transmission, water supply or water treatment. Site development plans will ultimately be available from the developer, but in the early stages of the planning process it may be difficult to get well-defined plans. In this case, direct interviews with the architect/engineer, or observation of procedures at similar sites elsewhere may be sufficient to establish a set of working assumptions.

After the land requirements associated with the site of the proposed refinery have been analyzed, the next step will be to estimate the residential, commercial, and public facilities requirements necessitated by the population influx associated with the proposed refinery. The Action Handbook: Managing Growth in the Small Community[54] presents a set of estimates of land requirements that may be useful in establishing order of maqnitude estimates. Each of these estimates (reproduced in Table 32) requires close scrutiny before physical planning commitments are made. Nevertheless, for long-range planning purposes, they provide a useful starting point. As the planning processes associated with residential, commercial, and public facilities expansion become more concrete, it will be possible to refine the earlier estimates and to deal more specifically with the geographic location of the expansion.

• Impact Analysis

Land use impact analyses are closely interrelated with community planning. Any given proposed refinery and its associated economic and demographic consequences require space. Although the amount of space required will be somewhat variable, the real flexibility comes in locating that space with its resulting impact on the remainder of the community. Land use is the surface expression of the combination of economic, demographic, and social forces working together within the framework of a complex natural environment. Therefore, when evaluating land use impact analyses, the following factors should be kept in mind. First, land use projections with and without the proposed refinery must be tied logically to economic/demographic analyses. Second, land use projections must be compatible with characteristics of the natural environment as well as with existing or planned man-made uses. Third, land use projections must reflect the priorities of the community with respect to the way in which the citizens wish development to proceed within their community.

TABLE 32

Land Requirements Per 100 Persons
Permanent Population Influx

	Acres
Elementary school	.28
Secondary school	.32
Water supply	.10
Sewage treatment	.10
Housing	6.38
Police	.006
Fire	.007
Medical	.025
General government	.003
Solid waste	.167
Parks/Recreation	1.00
Libraries	.014
Commercial land	.117
Industrial	1.20
Subtotal	9.72
Streets (.3 of subtotal)	2.92
Total Acreage	12.64

Source: Reference 54

3.9.4.5 Fiscal

Questions/Issues

Fiscal impact analysis has historically been an important component of the planning process, especially with respect to the evaluation of urban development proposals. The fundamental question concerns the effect of a given refinery on the expenditures and the revenues of local governmental units. This effect, the "net fiscal impact," is certainly not the only consideration in evaluating the desirability of a particular proposal, but is important, especially in the eyes of local government planners and elected officials.

The questions that must be answered are the following:

What will be the effect of a given proposed refinery on the public expenditures of local governmental units?

What will be the effect of a given proposed refinery on tax revenues that will accrue to local governmental units? What will be the effect on other sources of funds for which the governments may be eligible?

In light of the expenditure and revenue effects, what is the net fiscal impact of the proposed refinery?

In addressing these questions, three references are particularly useful.[54,57,62]

• Existing Environment

Description of the existing fiscal environment requires an evaluation of current expenditures, revenues, and indebtedness.

Expenditures

It is necessary to collect data on expenditures by function, on both current and capital account, for each jurisdictional unit in the study area. It is useful to have this data for the fiscal year that includes the first half of the last census year (so that relationships can be established between census and budget data) and for the most recent fiscal year for which actual expenditures are tabulated. Consolidated budgets will generally be available for all jurisdictions in the state auditor's office, although it will sometimes be necessary to go directly to the financial officer of the jurisdictional unit for information.

In some states, and for some units of government, data will be available in a secondary source that summarizes the budgets of all school districts in a state or of all counties or municipalities. If these data are available, it allows comparisons of the following type to be made. The first step is to put the data into a form that allows comparisons of the expenditures of different local jurisdictions to be made. This can be accomplished by putting the data into a per capita (or per student) form which can then be plotted on a graph with expenditures per capita on the vertical axis and population on the horizontal axis.

Revenues

As was the case with the expenditure data, it is useful to collect the revenue data for the fiscal year that includes the most recent year for which year-end budget documents are available. The state auditor's office will usually be the most likely location to find all the information in one place. With revenues, however, additional help can often be found in the publications of non-profit organizations designed to represent the interests of taxpayers. These organizations publish annual documents that summarize a large amount of fiscal data for the state in which they are located.

Indebtedness and Overall Fiscal Condition

An initial task is to describe the bonding capacity of each of the jurisdictional units in the study area together with their current levels of indebtedness. These data are available in the sources from which the expenditure and revenue data are obtained and are an important consideration when capital facilities impacts are studied.

A final task is to provide perspective on the overall fiscal condition of the jurisdictional units in the study area. This is somewhat more difficult than it sounds since no conclusions can be drawn by looking at the budget itself. The question at issue is whether the local public sector has been able to afford an appropriate level of public services and whether they appear to be able to continue to do so in the future. Thus, the inventory data on public facilities and services go a long way to answering the question of overall fiscal condition. Some additional insights can be gained, however, by completing an analyses of the revenue and expenditure data.

An indication of the pressure on local governmental units can be inferred from the level of the mill levy, since it is the major tax rate over which local officials have discretionary control. If the following symbols are defined,

E = total expenditures on current account
PT = property tax revenues
TV = taxable valuation
m = mill levy
OT = other taxes
GT = intergovernmental transfers
OR = other revenues

the necessary equality of expenditures and revenues can be expressed as

$$E = PT + OT + GT + OR.$$

Further, since property tax revenues are the product of taxable valuation times the mill levy, the equation above can be rewritten as

$$E = m \cdot TV + OT + GT + OR.$$

Thus, the local fiscal planning process can be characterized as starting with projections of non-property tax revenues, intergovernmental transfers, and taxable valuation and then balancing the benefits of higher expenditures with the costs of having to raise the mill levy. In general, the higher the mill levy (especially if it is high compared to that in similar jurisdictions) the more fiscal pressure the local government is under.

This information can be presented in two ways. First, it is useful to compare the mill levies for the units in the local impact area with average levies in the state. Second, it is important to know whether the mill levies have been changing over time, and, if so, to get an indication of why. This can be approached by taking the budget data for the most current year (t) and comparing the changes and the relative importance of the different revenue sources to data from the last census year (t_c). The information is even more easily interpreted if it is put on a per capita basis (POP) for the two years. Thus, the following information would be presented:

$$\left(\frac{E}{POP}\right)_{t_c} = m_{t_c}\left(\frac{TV}{POP}\right)_{t_c} + \left(\frac{OT}{POP}\right)_{t_c} + \left(\frac{GT}{POP}\right)_{t_c} + \left(\frac{OR}{POP}\right)_{t_c}$$

$$\left(\frac{E}{POP}\right)_{t} = m_{t}\left(\frac{TV}{POP}\right)_{t} + \left(\frac{OT}{POP}\right)_{t} + \left(\frac{GT}{POP}\right)_{t} + \left(\frac{OR}{POP}\right)_{t}$$

These data will show clearly which revenue sources have been keeping up with the rate of growth of population; what has been happening to expenditures per capita; and what the resulting effect has been on the mill levy. For example, expenditures per capita, taxable valuation per capital and other tax revenue per capita may all have been remaining steady, but intergovernmental transfers per capita might have fallen causing an increase in the mill levy. Presenting the data in this format makes it relatively easy to understand the major fiscal forces acting on each unit.

Projection of Impact

Projection of the future fiscal environment, both with and without the refinery must be accomplished for expenditures and revenues. The following lists possible projection methods.

Expenditures

The Fiscal Impact Handbook[57] examines six methods of projecting expenditures. Each method is carefully explained, its assumptions examined, its use demonstrated, and its results evaluated. Four of the most important are described below:

Per Capita Multiplier Method - This is the most commonly used method of expenditure projection and involves multiplying population increments by current per capita cost factors. The technique is most appropriate when the projected growth is relatively small compared to the size of the impacted area.

Case Study Method - The case study method is frequently used in impact assessments. It assumes that municipal department heads and school administrators best understand the cost implications of additional population or new students. These results are then added to the best existing projections of costs in the absence of the proposed refinery.

Service Standard Method - This method uses standard information, like that presented in the Facilities/Services section, to project personnel and facilities needs for each of a large number of municipal functions. The Handbook contains estimates of manpower ratios for four geographic regions for 11 different size categories of places. Current salary information can then be used to develop labor costs and other operating expenses can be related to the incremental labor requirements. Finally, capital costs are related to operating costs. It should be noted that this approach is often combined in practice with the case study method.

Comparable City Method - This method is particularly well suited to situations in which a proposed action is going to have large effects on a community's size or rate of growth. The technique relies on a set of tables that have been constructed which show how per capita expenditures vary by size of city (from 1,000 to over 1,000,000 persons) and by rate of growth for each of five categories of municipal services and for school district services.

Revenues

As was the case for the analysis of economic impacts, revenue impacts can be divided into direct and indirect categories. The direct component is concerned with the tax revenue that will be generated directly by the proposed refinery. (For example, a refinery in a county will add to assessed valuation thus increasing the potential property tax income. If a coal mine is proposed, various governments could receive increased severance or sales tax revenue.) The indirect impacts are those associated with the increased level of economic activity and include such things as sales and use tax receipts or receipts from property taxes on residential and commercial property.

The direct revenue impacts can usually be estimated using data on the proposed refinery and the existing tax structure. If the project will be subject to property tax, then the assessed valuation of the facility must be determined. Projected construction cost data and the applicable assessed valuation rates and current mill levy are usually readily available from the county tax assessor and the state department of revenue.

Severance or sales taxes are usually collected by the state and then allocated for various purposes. The distribution formula for the particular state in which the project is located must be analyzed and applied to the specific jurisdictions. Severance taxes are usually based on the value of production although some are on a per unit basis. In estimating both the direct as well as the indirect revenue flows, particular care should be taken to accurately show the time lags which are inherent in many revenue sources. For example, property taxes are usually based on the previous fiscal or calendar year. It is therefore unlikely that construction (and its attendant population impacts) will precede the flow of revenues from the impacting facility.

Estimation of the indirect revenue impacts is less straightforward. The indirect impacts will be on property tax revenue, sales tax revenue and income tax receipts. The key to calculating the property tax impact is the estimated increase in assessed valuation within the particular jurisdiction. Assessed valuation per capita can be used along with the population impact of the proposed refinery to estimate the change in total assessed valuation. An average per capita figure could be used for other types of property and the two summed together to yield the indirect impact on assessed valuation.

Estimating the property tax change associated with the change in assessed valuation is complicated by the fact that the mill levy is a function of the level of total expenditures in the jurisdiction relative to the total amount of revenue derived from other sources. If expenditures are increasing faster than revenues, and if there is no substantial increase in assessed valuation, the revenue deficiency must be made up by increasing the property tax rate. On the other hand, if total assessed valuation is rising rapidly, the mill rate may actually decrease. In essence the property tax rate bridges the gap between revenue and expenditures.

Changes in state income tax or in sales tax receipts can best be projected by estimating the relationship of past receipts to personal income. Assuming no change in tax rates, projected receipts can then be tied to personal income projections.

The change in remaining tax revenues may be able to be calculated by using a per capita figure. The population change associated with the proposed refinery can then be multiplied by the per capita rate and the impact on remaining tax revenues can be determined.

A final revenue category is intergovernmental transfers. These include income received at the local level from the state government and federal revenue sharing. In many instances, state intergovernmental transfers are the jurisdiction's portion of the sales tax collected by the state on state property and highway tax returned to the local government. Other times, however, pass-through grants from the federal government or special payments by the state are the source of this revenue and these are not directly related to the level of activity or growth of the area.

The second type of transfer is federal revenue sharing which complicates the historical analysis because it did not begin until the early 1970s. The allocation of this money is based on a formula using such variables as population, income, and unemployment. The amount of money given to a particular local government is dependent not only on the allocation formula but also on economic conditions in other areas of the country. In addition, changes in the allocation formula are difficult, if not impossible, to predict. This is not to say that this revenue category should be ignored. On the contrary, revenue sharing has been a major source of income for local governments and an attempt must be made to project future revenue flows and whether they might be affected by the proposed refinery.

<u>The Fiscal Impact Handbook</u>[57] presents methods to project some thirty different sources of revenue. The sources consist of local revenues (property, sales, and income taxes, and charges and fees) and

intergovernmental transfers. For each of the important sources of local revenues, procedural guides and examples for projecting source-specific revenues are included.

Net Fiscal Impact

When the analyses of expenditures and revenues are combined, the result is an estimate of net fiscal impact. It is important that this be done for each jurisdiction in the impact area and that careful consideration be given to timing.

Impact Analysis

Assessment of the following concerns will provide an analysis of the projected impacts.

Have the changed circumstances under which public services and facility delivery systems will be operating during the construction and operating phases of the proposed refinery been taken fully into account?

Does the revenue analysis reflect changes in economic and demographic activity expected to accompany the proposed refinery?

3.9.4.6 Social

Questions/Issues

Social resource investigations, while often neglected in impact studies, are a necessary part of the overall environmental impact assessment process. It is within the context of the social analysis that impacts from the remaining elements of the human environment are combined and evaluated.

Major questions and issues which must be addressed by the planner in a social impact assessment include the following:

What is the nature of the existing social structure?

How and to what extent will the proposed refinery change this social structure?

How will affected persons view these changes?

Description of the Existing Environment

Historical Perspective

In order to understand the existing environment and to assess potential impacts more adequately, a brief historical sketch of the study area should be developed. The following is a list of basic categories and issues, outlined by Abt Associates,[69] which could be considered in an historical examination of the area:

Early Settlement of Planning Area
- Circumstances under which initial settlement occurred
- First settlers
- Dominant values of early settlers
- Economics of settlement
- Early growth rates
- Major events in early settlement
- Sources of general influence from outside communities
- Emerging economic structure
- Emerging social stratification, i.e., social classes or groups
- Significant shifts in values
- Key elements of community life

General Development of Communities to Present Time
- Demographic characteristics
- Major significant events
- Economic picture
- Cultural traditions
- Political characteristics

This historical perspective may be obtained from the cultural resource investigation, if the level of information is applicable. If the data is collected as part of the social impact study, however, it should be noted that time and effort spent on this portion of the social assessment should be kept in proportion with the requirements for the total study.

Information sources, aside from cultural resource investigations, will include:

Public records - census, school and town records, county archives, surveyor's notes, and other state and regional documents.

Privately-owned records - library collections, newspapers, family histories and biographies, directories, maps and local church and fraternal records.

In addition, interviews with local residents will provide helpful information and insights.

A description of the existing social environment follows an examination of historical information and precedes the impact analysis. In general, it will be described both quantitatively (social profiles) and qualitatively (community life descriptions).

Social Profiles

Relevant social characteristics for affected communities and groups should be collected and compiled as social profiles. Social characteristics which may be included are: demography, public services, social well-being, economy, social structure, and community response.[70] In general, collected data will be statistical or quantitative in nature (for example, average school classroom size, number of types of crime per capita, percentage of labor force employed and number of organizations making public statements) and may be displayed in tabular form. This process will provide a basis for comparison with appropriate county, state, regional, or national statistics.

Descriptions of Community Life

This qualitative portion of the existing environment description should describe general lifestyles, customs, attitudes, values, and other typical behavior patterns which, in general, characterize an area or group. This information is generated to supplement and support the more statistical social profile. The following types of issues, as outlined by Abt Associates[69] could be included:

Descriptions of various groups making up the community,
The nature of work and leisure life
Important patterns of social life
Changes in politics and institutions
General reactions to various plans
Aspirations for the future
Special variations in any of these patterns by group.

Community and Social Structure Data Sources

Data sources can be divided into three principal categories: (1) primary data sources; (2) published secondary data sources; (3) local secondary data sources, usually unpublished. Each source has advantages and limitations which affect its utility. The following is a brief discussion of each category.

Primary data - Interviews with informed respondents, such as community leaders, officials, and interest group representatives are important sources of primary information. In addition, community surveys and other public participation programs can provide timely, project specific data.

Published secondary sources - The main advantage of using published secondary sources is that they are easily accessible, and therefore relatively inexpensive to use. Most university libraries and many public libraries contain census materials and other similar government documents. Unfortunately, much of the detailed census information useful for social assessments is available only for counties, or cities of over 50,000 persons. These two factors may present difficulties since (1) the boundaries of impact areas for specific projects seldom coincide with county or city boundaries, and (2) projects may be built in rural areas outside of major population centers. Therefore, these data sometime serve only as rough approximations for measuring project impact.

Other secondary data sources - Many additional sources of secondary data exist which are collected at the local level from various public offices. Considerations which affect the usefulness of the information available from each office include: accessibility and frequency and accuracy of information recording. Most county records have guaranteed public access, but special permission must be obtained to gain access to certain county records, such as bills of sale, which are considered confidential. Even if access is obtained, however, the data may still be difficult to use. For example, raw data are available for calculating the effect of a project on average housing values. However, this would require examining each bill of sale during specific time periods and computing averages. This procedure is obviously extremely time consuming. Less precise estimates, based on assessed valuation, are easier to collect. Accessibility also depends upon the format of the required information. In general, data are available in the form of printed documents, reports, maps, computer output, or books. In addition, the usefulness of any data depends on the timeliness of the information. Some sources collect information annually, monthly, or as the data occur. A final evaluation consideration is the data's accuracy and completeness.

Additional important secondary data sources for social impact analyses are local newspapers and records of meetings, hearings, and legal proceedings. Although these sources are not without limitations, they will often be the most reliable source of information from which inferences can be made for area values and attitudes and how they change over time.

- Projection of Impact

After baseline social resource information is compiled, projections of the social environment are made both with and without the proposed refinery. The following methods can be used to project both impacts.

The amount of impact on an area by a refinery will depend primarily on two characteristics:

(1) Actual refinery characteristics - What kind of project is it? What other similar projects have been constructed in the area? Has the community been affected by other industrial growth? What will the size and nature of the construction and operation workforces be?

(2) Community (group) characteristics - How large is the community? Where is it located relative to the refinery site? What are the community values?

Determination of social impacts, both with and without the proposed refinery and/or other actions, depends directly on input from the demographic, economic, and services/ facilities environmental elements discussed above. Projections of changes in community demographic, economic, and services/facilities characteristics must be determined and placed in the social assessment process in order to identify resulting social well-being, social structure, and community response impacts. The interrelationships between these elements may be highly complex.

Following the identification of project impacts on the study area's social environment, an assessment must be made on the effects of those impacts, that is, are they negative or positive as perceived by the affected communities/groups? For example, is it desirable to have new residents in an area? Will a shopping center disrupt or unify the surrounding neighborhoods?

Persons conducting a social impact assessment must work closely with local residents, groups and communities. They may occur through direct contact (i.e., public participation programs) or through more indirect contact, such as representative committee groups and agency contact programs, or through a formal ethnographic study such as Gold[71] described earlier in this section. It is through local contacts and communication programs that local residents may evaluate identified impacts as positive or negative.

- Impact Analysis

Throughout the social impact assessment process, the planner should consider the following questions. These questions were developed to help the planner evaluate the quality of the assessment of the social environment.

Were the impacts addressed in the following terms and situations?

- direct and indirect
- long and short term
- among different geographic areas
- among different communities/groups
- at the individual, neighborhood, community, local, regional, and/or national level

How large are the issues surrounding the project? The bigger the issue, the more explicit and detailed the impact assessment should be.

Is the magnitude of impacts identified?

Does the report provide decision makers with adequate information for weighing alternatives?

Is the impact assessment methodology documented and replicable?

Would other persons, utilizing the same methodology, develop similar conclusions?

3.9.4.7 Cultural Resources

The cultural resource investigation is developed around two major components: history and archaeology. The archaeological component deals with information concerning the life and culture of people who lived prior to written history, while the historical component addresses people and events within the recorded past.

Cultural resources are one part of the total environment which must be considered in an environmental assessment process. It is important that these resources be identified and included in the process, particularly given their non-renewable nature; i.e., once modified or destroyed, it is unlikely that historical and archaeological resources may ever be restored to their original value. It is important that both types of resources be identified and their values be established before project decisions affecting them are made.

Historical resource investigations revolve around (1) descriptions of major themes or periods of development, and (2) the location of areas, sites, and structures of historical significance. Archaeological studies involve the location of sites (through secondary source information, fieldwork and predictive modeling), and the characterization and classification of remains to determine their relative significance. The location of archaeological sites includes investigating locational variables such as ecological communities, physiographic features, and drainage patterns (as they presently exist and as they existed historically and prehistorically)

The significance of both cultural resources must be considered at a local, regional, state, and national level. State and National Registers of Historic Properties must be contacted to determine the location and status of any designated or nominated areas, sites, or building. In addition, identified resources must be individually evaluated to determine whether they might be eligible for protection under Title 106, National Historic Preservation Act of 1966 and other appropriate federal regulations.

Due to the technical nature of the resource identification and assessment process, local planners should solicit help from area professionals. The best source of local and/or regional historical and archaeological expertise will be local universities and colleges. Additional information sources include:

State, county, and local museums
State and local archaeological and historical societies
State historic preservation officers
National Register of Historic Properties
Federal agencies: e.g., BLM, USFS, National Park Service.

3.9.5 Management Techniques for Mitigating Socioeconomic Impact Precipitated by a Refinery Development

Impact management refers to efforts taken by both the public and private sectors to prevent, guide, or remedy the significant social and economic changes associated with energy or other development related projects. The construction and operation of a refinery can provide significant benefits to the population and economy of an area in which it is located. There will be expanded employment opportunities, a more diversified economy, development of public facilities and services and the strengthening and stabilization of the tax base.

The severity of the impacts on communities depend on several factors including original population size, rate of growth, level of unemployment, condition of local services and facilities and quality of planning. Of all these indicators, the rate of growth (attributable to the development) appears to be the primary indicator of the level of severity of the impacts.

While the benefits to the community/county/region of a refinery can be significant relative to the costs they accrue overtime, whereas the negative impacts demand immediate attention and moreover are locally confined. The objective of this section is to provide (1) an overview of the socioeconomic impact management process; and (2) a concise but comprehensive set of guidelines for states and local planners in exercising this process.

3.9.5.1 Components of the Impact Management Process[80]

The major components of the impact management process are the community's existing functional capabilities, existing planning and management capabilities, goals, impact amelioration requirements, planning and management needs, potential planning and management resources, and recommended planning and management strategies.

Existing Functional Capabilities. To determine accurately a community's ability to manage expected or potential social impacts, two sets of baseline information are necessary. One of these is data on the existing capabilities of local governments to provide public services such as sewer and water, road maintenance, schools, etc. It is particularly important to determine the "carrying capacity" of each of the services or functions the local government is expected to provide. If the service is presently operating close to or at full capacity, expansion may be required if the population increases rapidly.

Existing Planning and Management Capabilities. The second kind of baseline information necessary to assess a community's ability to manage impacts is data on its existing planning and management capabilities. The extent of these current capabilities will directly affect the community's needs for additional planning and management programs to cope with the anticipated social impacts. Existing capabilities include the presence of professional or experienced planning staff, the amount of money available for planning in the community, and a demonstrated willingness on the part of the community to take part in a planning process.

Community Goals. A community's current and future goals will also directly affect its reponses to anticipated social impacts. Such goals as the amount and direction of desired growth and the quality and style of life valued by a community are critical parameters for impact management decisions. If a community does not want permanent growth, for example, then an overload on some existing public service for a short period (such as during the construction of a project) might be a wiser planning decision than expanding services to meet the demands of a large population that the community does not want.

Impact Amelioration Requirements. These requirements - which are determined by the predicted socioeconomic impacts, the community's existing functional capabilities, and its goals - specify the problems the community will likely face in coping with the expected impacts. What additional mitigation or amelioration measures are needed to effectively manage those impacts will then become apparent. These impact amelioration requirements might include expanded employment services, property re-evaluation, additional housing, more roads and schools, expanded recreational facilities, or new community organizations. Detailed specification of these facilities, or new community organizations. Detailed specification of these probable amelioration requirements for a community is the most crucial step in the total impact management process.

Planning and Management Needs. Once its impact amelioration requirements have been determined, a community can then assess the ability of its planning and management capabilities to meet these requirements. For example, will additional professional staff be required to design or administer programs to alleviate social problems or service overloads? Do community officials have sufficient expertise to determine how and where additional revenues may be obtained, and how and where technical assistance may be available? A community must evaluate carefully its ability to plan for the expected sodial impacts identified and whatever additional planning and management needs it will experience as it seeks to cope with those impacts.

Potential Planning and Management Resources. If the community requires additional financial or technical resources to meet its planning and management needs, potential sources for these resources must be identified. This is accomplished through a careful examination of all existing and potential programs available at the state and federal levels, as well as whatever technical and financial contributions may be obtained frcm the project developer. The applicability of these programs and their contribution to the local community must also be carefully evaluated.

Recommended Planning and Management Strategies. All the informantion gathered in the preceding steps of the impact management process feeds into this final component. Based on (1) an evaluation of the need for impact management or amelioration programs, (2) the capabilities of the local government to meet these needs, and (3) the potential availability of additional planning and management resources, a community can develop a planning program to manage any expected socioeconomic impacts. This program should include recommendations for the specific strategies to be used to manage the impacts, as well as provide overall directions for future community development as it copes with a variety of socioeconomic impacts.

TABLE 33 GUIDELINES FOR SOCIO-ECONOMIC IMPACT MANAGEMENT

1. INVOLVE THE PUBLIC IN THE COMMUNITY POLITICAL PROCESS: If impact management efforts are to accurately reflect the goals and needs of a community, citizens must take part in local political decision-making processes. A community run by a handful of people or one interest group will reflect only the desires of that small fraction of the community. The public must be convinced that impacts will occur but can be minimized or ameliorated through a planning process that involves citizens in identifying both problems and their solutions.

2. DEVELOP AND IMPLEMENT A COMPREHENSIVE COMMUNITY PLANNING PROCESS: Comprehensive planning is vital for coordinated impact management. A comprehensive planning process can assure that all important social and economic changes are examined in a systematic fashion. This planning should be an integral part of the overall decision-making process.

3. DEVELOP AND MAINTAIN AN ACCURATE AND CURRENT INFORMATION BASE: Planning and preparing for social and economic impacts requires accurate and timely information. Local officials must be aware of potential data sources and be willing and prepared to collect whatever data will be required to understand the effect of a proposed project on the community and to meet the resulting community needs. This particularly includes changes that will affect public service and budget decisions.

4. INITIATE A COOPERATIVE WORKING RELATIONSHIP WITH THE DEVELOPER: Local governments should try to develop a cooperative working relationship with the developer so that they have access to necessary information. This relationship will also increase the likelihood that the developer and community will cooperate in developing planning strategies. A regional government or council of governments (COG) may be in the best position to facilitate an information flow from developer to affected community.

5. IDENTIFY IMPACTS EARLY: Local and regional government must have sufficient time to plan for anticipated social and economic impacts. This includes time for any needed new applications, time to wait for other governments' budgetary and funding cycles, and time for the construction of any needed new community facilities. This activity should be performed early to ensure that the impact management process will be integrated into the overall community planning and decision-making processes. In fact, mitigation measures for social and economic impacts often require more lead time than mitigation measures for environmental impacts. Thus it is crucial that the identification process begin early.

6. FIND AND OBTAIN ADEQUATE RESOURCES: An important aspect of planning for community impacts is knowledge of the resources (including local legal powers) that exist at the local level and how to obtain necessary additional financial resources or technical aid. Local government should seek this information as soon as it is aware that potential impacts may occur.

7. ESTABLISH INTER- AND INTRAGOVERNMENTAL COORDINATION AND COMMUNICATION: It is vital that regular communication occur among all affected agencies so that all can contribute suggestions and possible solutions to problems as they arise. Regional governments may be the most appropriate vehicle for assuring that this communication takes place.

Source: Reference 80

3.9.5.2 Guidelines for Socioeconomic Impact Management*

The key elements necessary for successful impact management are described below. The discussion is divided into two parts: (1) basic guidelines essential to the effective management of community social and economic impacts; and (2) the interrelationship between the planning and decision-making processes.

Identified are seven guidelines that can be used by local officials and planners to manage the social and economic impacts associated with refinery developments. The guidelines are summarized in Table 33 and detailed in a step-by-step discussion below.

Underlying these guidelines for impact management are two critical points. First, to implement the guidelines, local governments may have to expand their planning and management capabilities. Although the first three guidelines pertain to ongoing planning efforts in most communities, the last four guidelines are project-oriented and may require that a government hire additional personnel or contract outside consultants to perform needed professional services.

Second, local governments must be able to cope with the uncertainty that accompanies the early stages of most large-scale developments. To meet the needs that will arise when rapid growth occurs, the government must develop plans, obtain funds, and possibly build facilities or develop services before the project beings. And because of the long lead time required for programs that depend on federal or state funding, local governments must anticipate their requirements before the nature and scope of these needs are at all definite. To deal with such uncertainty, communities must often develop several alternative plans, identify alternative sources of financing, and prioritize anticipated social impacts.

* Significant portions of this section have been extracted from "A Impact Assessment and Management Methodology Using Social Indicators and Planning Strategies," Reference 80.

Step 1. Involve the Public in the Community Political Process

In many small communities, particularly in rural areas, the people desire little governmental control over or interference with their daily lives. Hence, local government provides few services of facilities. This system works well as long as few demands are placed on the public sector. However, when a community is faced with a large-scale energy development project and an influx of people with different values or needs, it must make numerous critical decisions regarding all aspects of its future growth and direction. Under these conditions, it becomes imperative that more citizens be involved in the community decision-making process. Without widespread public awareness and involvement, crucial decisions concerning the entire community will likely reflect the interests of only a small minority of the population. If citizens are not already informed about and involved in the local political process, local government should take immediate steps to encourage such participation so that the decision-making process will consider the concerns of the total community.

Must be Convinced that Impacts Will Occur. It is not uncommon to find some local officials and residents who are so enthusiastic about a proposed project that they refuse to acknowledge or discuss potential social and economic impacts. Individuals and groups who desire growth may want to do nothing to discourage project development in their area, and may feel that recognition of potential impacts might be interpreted as a negative response to the project. In addition, they may be convinced that the benefits outweigh the negative effects. However, to prepare most effectively for the changes that will take place (even though they may be welcome changes), local officials and citizens must recognize that there will be impacts with which they must deal. Planned change can be used to effect improvements and to reduce some of the costs of growth for a community.

Must Support the Planning Process. Once the community recognizes and accepts the fact that social and economic changes will result from the project, officials and residents must be willing to plan for these changes. Such planning should include budget analyses to re-examine priorities, land use planning to better control the direction of growth, and comprehensive planning to systematically provide community services and facilities and to coordinate various elements of the public sector. Citizens and elected officials should be aware that while change may be used to improve local services and facilities, such improvements depend on foresighted planning. Elected officials must be willing to participate in planning efforts and to provide the appropriate mechanisms for implementing suggested planning approaches and strategies. In addition, community residents should actively support or even initiate efforts to plan early for the anticipated impacts.

Must Develop and Use Communication System in the Community. A communication network must be established to facilitate the availability and exchange of information among citizens in communities and the counties affected by rapid growth. In most communities a weekly newspaper can be used by the developer and by local, regional, and state agencies to inform the public about the nature and progress of the development and the related community growth impacts. The public also may use this vehicle to express their opinions and concerns about the development.

Step 2. Develop and Implement a Comprehensive Community Planning Process

To use their resources most effectively and to develop appropriate strategies for coping with identified social and economic impacts, affected communities must have comprehensive planning processes. This process should be ongoing and flexible enough to deal with whatever changes the community experiences. Comprehensive planning helps to guarantee the effective management of impacts. This process will examine all potentially affected or changing aspects of community life, from health care and mental health to the provision of police and fire services and water and sewer facilities. Moreover, all of these separate elements must be integrated into a comprehensive plan that treats the total community as a dynamic interrelated system.

Relate Planning to Land Use. Community planners and planning commissions are usually most interested in land use. When communities are faced with rapid growth, however, planners and local officials must broaden their concern to include many other planning issues. By relating these other concerns (e.g., projection of project-related revenues and expenditures, the assessment of social and economic impacts, etc.) to land use, decision makers and planning commissions will understand better the need for a comprehensive approach to community planning.

Relate Planning to Decision-Making Process. Planning provides a framework for informed decision-making. To be useful, planning must relate to and influence critical local decisions when they are being made. Thus, elected officials and other public servants must support and understand the planning process and work toward its full implementation.

Step 3: Develop and Maintain an Accurate and Current Information Base*

A local government facing significant social and economic changes requires two types of information. One is data on existing characteristics, conditions, and trends in the community and the county. The other is projected data on future characteristics, conditions, and trends in that area.

An accurate information base is essential if planning efforts are to effectively identify and implement appropriate measures to cope with social and economic impacts. Thus a local community should begin to establish the data base needed to plan for and manage anticipated social and economic impacts at the time a development project is first announced.

* This step corresponds to the description of the existing environment with respect to each of the seven human environment components described in Section 3.9.5.

What to Include in the Information Base. The categories of information to include in such a data base are listed in Table 34. This information provides a baseline description of the community before the impacts occur, (i.e. without the proposed refinery). The sources of data required to satisfy this information base were discussed in the relevant areas of Section 3.9.5.

Step 4. Initiate a Cooperative Working Relationship with the Developer

The company initiating a development project is potentially the most accurate source of information about the nature, scope, and timing of the project. It is important that the developer provide the community with accurate and timely information on the construction schedule, size of work force, material transporation needs, tax information, and other relevant information about the project. It is also critical that the developer and the local government establish and maintain a close working relationship throughout the construction and operation of the project, since all parties generate information that is essential to the others' efforts.

While the project developer is likely to make contact with affected communities to establish good public relations, frequently it is still up to the local government to ask for specific information about the characteristics of the project that are needed to anticipate and plan for community impacts. Therefore, the affected governments must be prepared to take the lead in establishing a working relationship with the developer. In some situations a regional council of governments can play a useful coordinating role, acting as a mediator for all affected local governments.

The Exchange of Information. It is desirable that the developer and the community share information and plan for the project together, as far as possible. Local officials will need various kinds of information from the developer, such as project construction schedules and labor force

TABLE 34 SOCIAL AND ECONOMIC INFORMATION DATABASE REQUIREMENTS[a]

Population Characteristics

- Population size by sex, age, race
- Degree of urbanization
- Family size
- Education attainment
- Labor force skills required

Economic Characteristics

- Gross economic income
- Economic base/diversity
- Employment/unemployment rates
- Job availability and diversity
- Job training availability
- Family and personal income
- Cost of living
- Retail facilities
- Tax base (include property, business and occupation, utility and sales

Community Structure

- Associations
- Mass media

Housing

- Mean market value
- Vacancy rate
- Housing distribution type
- Public housing
- Existence of federal or state assistance--type and amount
- Rental scale

Social Well-Being

- Crime and delinquency
  - violent crimes/1000 population
  - property crimes/1000 population
  - arrests for disorderly conduct, drunkenness
- Mental health
  - number of clinics and contacts by type
- Emotional difficulties
  - number of incidents truancy/student population
  - number of incidents vandalism/student
- Poverty
  - proportion of families below poverty line
  - proportion of families receiving public welfare

Planning and Administrative Capabilities

- Existence of planning bodies (local and regional) by type
- Number of planners/1000 population
- Existence of federal or state assistance by type and amount
- Total amount of money allocated for planning

Public Services

- Government
  - number of employees/administrators
  - total local revenues
  - total local expenditures/capita
- Education
  - total enrollment by school
  - capacity by school
  - number of school districts and boundaries
  - average student/teacher ratio
  - expenditures per student (including capital maintenance)
- Health services
  - number of hospitals and location
  - number of beds/hospital
  - occupancy rates/hospital
  - type of emergency services
  - number of physicians/1000 population
  - number of clinics/contacts and capacity
  - federal or state assistance
- Police and fire protection
  - number of officers/1000 population
  - fire rating
  - federal or state assistance
  - expenditures valuation
- Social services--public and private
  - type of service
  - expenditures per capita
  - existence of federal or state assistance--type and amount
- Parks, recreation
  - number libraries/museums
  - acreage, location, type of parks utilization rates
  - indoor/outdoor recreation type and number (pools, ball parks, etc.) utilization rates
  - number of community centers
  - existence of recreation plan or program
  - existence of federal or state assistance
  - expenditures per capita
- Transportation
  - availability of public transit
  - existence of local plan for streets, roads, and transit
  - public parking availability
  - streets and roads
  - average daily trips or vehicles/day
  - expenditures per capita--capital and maintenance
- Public works/utilities
  - Water
    - existence of local plan for water supply development
    - expenditures per capita
    - demand
    - capacity
    - number of districts and service boundaries
    - existence of federal/state assistance
  - Sewer/sanitation
    - existence of local plan for sewer system development
    - expenditures per capita
      - demand
      - capacity
      - existence of federal/state assistance
      - number of districts and service areas

(a) To be most useful, it is important to collect these data at several points in time in order to monitor the changes resulting from project development. (Possible data collection periods include one point before project inception and several points during construction. It will be necessary to collect some data monthly or quarterly once construction begins.)

Source: Reference 80

requirements. The developer, in turn, will need to know about local zoning ordinances, tax rates, and other factors that will affect the project. The existence of an ongoing working relationship will facilitate the exchange of such information.

State and Local Powers. State and local governments possess certain powers that can be used to assure that the developer takes social and economic factors into consideration and complies with applicable restrictions and requirements. Local governments should be aware of the nature and extent of leverage they can exert through techniques such as local zoning and comprehensive planning powers, as well as participation in relevant state or federal decision making.

The Developer's Role. The developer's role in managing community impacts is in a state of evolution. It is therefore difficult to make generalizations about the extent to which a developer will consider local values and how much responsibility it will assume for providing assistance for social impacts generated by its project. In the past, developers have often felt that community impacts were not their responsibility. This situation is beginning to change, however, and many developers are taking some initiative in helping communities to manage impacts. On the other hand, more local governments are also demanding that developers assume responsibility for impacts they generate. The current trend is for the developer to make early contact with affected communities and to negotiate the level and types of assistance it is prepared to provide to the community.

Step 5. Identify Impacts Early

Local governments affected by energy development projects are particularly in need of early and accurate information regarding the project so that they can initiate planning to meet the resulting needs. They also must begin early to set up a communication process with all affected parties and interested observers, including appropriate federal and state officials, as well as the project developer.

Planning Coordination. It is essential that small and/or rural local governments work in coordination with other governmental agencies, including regional councils of government, throughout the duration of the project. The earlier all affected governments are informed of the project, the easier it is for them to establish such coordination. Serious problems also can be caused by lack of appropriate notification and identification of impacts as they occur. This situation causes local governments to lose critical time needed for their own planning and budgetary processes, and for their funding applications to other governmental agencies. The regional government can, in some situations, facilitate this coordination and communication by acting as a clearing house for information.

Coordinate with Other Governments' Budget Cycles. State and federal governmental levels often do not have the same budget cycle as a local government and thus may require extensive lead time for any new funding request. In addition, state and federal agencies may be constrained in what and who they may fund through priorities set each year by state and federal policy makers.

Step 6. Find and Obtain Adequate Resources

Planning for and managing the social and economic impacts associated with a large development project requires massive commitments of personnel time and can require additional financial resources. Many communities faced with a large project have little idea of how to plan for the changes and impacts such a project will bring. Lacking familiarity with the range of potential social and economic impacts, local officials are likely to have difficulty knowing beforehand what changes to expect and what resources to seek. This lack of knowledge (and sometimes appreciation) concerning both needs and sources of additional resources exacerbates the problem of coping with the impacts. Thus, by the time community officials recognize the problems and know what kinds of resources they need, it may be too late to obtain some forms of assistnace that might have been available with earlier planning.

Adequate Staff Time. Most communities faced with the prospect of an influx of hundreds of construction workers and their families will spend large amounts of staff time assessing and planning for potential impacts. For many communities this additional staff time is not easily made available. Other programs must suffer while people are temporarily assigned to the impact study. One alternative to this procedure is for the community to obtain additional funding for this planning effort. Another more immediate solution is to solicit citizen volunteers to help with local data gathering efforts. Such volunteers can make significant contributions to the community, if they have professional staff support.

These volunteers can be organized into distinct task forces. The task forces could develop a comprehensive picture of the community through its major responsibilities of gathering detailed information, assessing impacts in their specific functional areas, and translating future needs into preliminary community goals. An example of the work scope undertaken by a task force for a specific functional human environment component is exhibited in Table 35. The EPA-Action Handbook[54] has compiled similar task forces to evaluate each primary component of socioeconomic assessments.

Financial Resources. If it is obvious to local planners and decision makers that a community's existing financial and technical resources will not be adequate to cope with the predicted social and economic impacts, outside additional resources then must be sought. In some cases these resources may be needed only temporarily, until property taxes on a project begin coming into a community. Various state and federal programs are specifically designed to provide community impact assistance.

Most financial assistance is available through federal programs, while state assistance is usually limited to technical assistance. Major sources of such assistance are several ongoing federal programs for which impacted communities may be eligible. These programs include impact assistance under the Coastal Zone Management Act; Economic Development Administration grants for community facilities; Department of Health, Education and Welfare grants for family health centers and emergency medical serivces; and Housing and Urban Development community block grants.

TABLE 35 TRANSPORTATION AND CIRCULATION TASK FORCE

CONDUCT AN INVENTORY OF THE CURRENT SITUATION, INCLUDING AT LEAST THE FOLLOWING ELEMENTS:

- Federal, state and local roads in the region, including size, function, carrying capacity, conditions and hazards.
- Other modes of transportation, i.e., railroads, airports, bus routes, sidewalks, paths, bike paths, horse trails, etc.
- Future transportation plans of federal government, the state, regional agencies and counties.
- Sources of transportation revenues.
- Number of parking spaces and location.
- Local construction and maintenance programs.

EVALUATE TRENDS AND IMPACTS

- Have roads been of adequate capacity and condition?
- What changes and trends have occurred relative to transportation needs?
- What impacts would large scale development have upon transportation facilities and routes?

EXAMINE ISSUES RELATED TO TRANSPORTATION, INCLUDING BUT NOT LIMITED TO THE FOLLOWING:

- Are roads in the area capable of serving future demand?
- Are roads in adequate condition?
- Do plans of other agencies conform to local plans?
- Are there traffic hazards, e.g., dangerous intersections, railroad crossings, etc.?
- Are there transportation needs for special populations, e.g., elderly, handicapped or youth?
- What public transportation needs exist?
- What types and sizes of streets are desirable for newly developing areas?
- How could pedestrian access be encouraged?

DEVELOP MAPS DESCRIBING VARIOUS MODES OF TRANSPORTATION, INCLUDING CAPACITIES, TRAFFIC COUNTS, AND LOCATIONS OF PLANNED/NEEDED IMPROVEMENT

TABLE 35 TRANSPORTATION AND CIRCULATION TASK FORCE
(CONTINUED)

DEVELOP PRELIMINARY GOALS AND POLICIES, BASED ON THE INVENTORY, ISSUES AND COMMUNITY NEEDS WHICH WILL:

- Insure adequate capacity of roads.
- Avoid conflicts among various transportation modes.
- Encourage development of alternative forms of transportation, e.g., public transportation, bikeways, and pedestrian ways.
- Assure safety and adequate maintenance of roads.
- Serve the needs of all segments of the population.

WRITE A REPORT WHICH DESCRIBES PROBLEMS, ISSUES AND AREAS NEEDING IMPROVEMENT RELATIVE TO THE GOALS AND POLICIES

RESOURCES

- Federal - Department of Transportation
- State Agencies
- Regional Agencies
- County - Transportation and Planning Departments
- Local Governments
- Local Surveys (Utilize college and high school students)
- Universities
- Studies
  - Regional planning programs
  - Multi-state planning studies

Source: Reference 54

Awareness of Community Limitations. Local governments should be aware of any limitations in their state regarding local generation of new revenue sources. Local officials must be thoroughly familiar with their bonding limitations and capacities. They also must have knowledge of all other capital projections in the community in addition to whatever new facilities will be required by the project work force. They should be aware that bonding companies won't necessarily speculate with a community since large risks are involved in the construction of energy facilities. Finally, local officials must operate under the constraint that general obligation bonds depend on voter approval, which is not always easy to obtain.

Step 7. Establish Inter- and Intragovernmental Coordination and Communication with all Affected Agencies

Certain impacts of the development project may create severe problems for a community and are likely to raise complex and difficult questions concerning who will assume responsibility for the impacts, what are the best techniques for forecasting them, what are the most appropriate planning strategies for impacts, and what and where suitable sources of financial aid for the impacts can be found.

Make Numerous Contacts. The above questions become complex partly because their solutions involve many agencies at all levels of government. This makes it imperative that local governments in affected areas establish and maintain communications with other local and regional as well as state and federal agencies involved in local assistance. Without such contacts, local government is not likely to know about or take advantage of potential sources of technical and financial assistance, or may not be aware of its responsibilities in applying for such assistance. Most state and federal assistance is available only to those communities that apply for funds, with the exception of some revenue-sharing funds. Presumably, therefore, assistance goes to areas where it is wanted and needed. However, this arrangement also puts the primary burden on local governments, which may not know about potential sources of aid or application procedures. Communication with relevant agencies will help local governments to best use all potential resources. A regional planning organization, if there is one, is a logical clearinghouse for such information, and can facilitate communication among local governments and between local, state, and federal agencies.

Discuss Mutual Problems. It is quite important in large-scale development situations that the various affected local and regional agencies talk with each other regarding mutual problems and potential solutions. Any agency rivalries which impede an efficient problem-solving operation need to be put aside when planning for a project that can substantially affect the entire community. Well-coordinated local and regional governments, with representatives who confer regularly with other local and regional officials and appropriate state and federal officials, are a crucial requirement for adequately managing community impacts. Such organization is important when a local government is requesting funds from new sources such as federal agencies, and when it is negotiating with the project developer. It also strengthens the government's position when bargaining for policies and actions that can directly benefit the community.

Summary

All of the guidelines presented here have a temporal factor. If the timing is not correct, it may be difficult to initiate certain impact management steps. It takes time to formulate plans, find solutions, and obtain money to build facilities or implement programs. Local government therefore must estimate timing needs and plan their actions accordingly.

Early contact with the project developer is essential for accurate identification of potential impacts, which in turn is vital for adequate planning. Effective planning also requires substantial community involvement and commitment, knowledge of all available resources and all government agencies involved in the impact planning process, and well-prepared financial planning. Thus, one can quickly see that all the impact management guidelines interact with each other, and that these guidelines must be initiated sufficiently prior to the beginning of the project if the local community is to plan effectively for and manage the resulting social and economic impacts.

3.9.5.3 Conclusions

In this discussion of social and economic impact management, guidelines have been established to provide local planners and decision makers with an overall understanding and appreciation of several key actions, processes, and capabilities which local governments must demonstrate if they are to respond quickly and effectively to large social and economic impacts, As one can see in examining these guidelines, the ability of local governments to cope with rapid growth impacts depands largely on three interrelated factors: 1) the timely availability and use of information within 2) a comprehensive planning framework which is 3) an integral part of the polical process in which citizens are actively involved. State and federal levels of government are not likely to effectively manage social and economic impacts occurring in a local area. Rather, local governments, as representatives of local interests and values, must be the moving force in this whole process of determining what is an impact, whether it is beneficial or adverse, and what, if anything, needs to or will be done to respond to it.

Finally, it is important that the residents of the local area take an active interest and role in the local decision-making process. If only a small segment of the community's residents are involved in this process, problems can arise when the community is faced with rapid growth. Additionally, good administrators are needed to effectively deal with growth-related impacts and with the range of citizen concerns and values that will surface when citizens become involved in the decision-making process. The ability of these administrators--elected officials in small communities or professional staff in larger communities--is a principal factor determining a community's capability for managing social impacts. In short, competent and involved people make the impact management process work effectively.

4.0 REFINERY REGULATORY REVIEW*

There are a number of federal regulations which could have an impact upon refinery siting, construction, operation, modification or expansion planning and decisions. The regulations which are reviewed in this section are:

- National Environmental Policy Act
- Clean Air Act
- Federal Water Pollution Control Act
- Resource Conservation and Recovery Act
- Coastal Zone Management Act
- Toxic Substances Control Act
- Other regulations concerned with the environment

Summaries of these regulations and a decision diagram are presented for National Environmental Policy Act, Clean Air Act, and the Federal Water Pollution Control Act. Copies of these regulations and relevant reference material are presented in the appendix.

* The following sections are based on references 83-86 and presented herein after substantial revision, modification, and alteration of focus.

4.1 NATIONAL ENVIRONMENTAL POLICY ACT

4.1.1 Summary

- National Environmental Policy Act (NEPA) requires an Environmental Assessment and generally an Environmental Impact Statement on major federal actions significantly affecting the quality of the human environment -- this includes issuance of federal permits or approvals for industrial plants, unless individual statutes provide an exemption.

- Chief Federal Environmental Statutes:

  Clean Water Act -- NPDES permits subject to NEPA if issued by EPA to "new sources"

  Clean Air Act -- Some actions exempt from NEPA

  Fuel Use Act -- Some actions exempt from NEPA

  Resource Conservation and Recovery Act -- Permits issued by EPA for hazardous waste management facilities will be subject to NEPA

  Dredge and Fill Permits -- Corps of Engineers permits are subject to NEPA

  Coastal Zone Management Act -- Approval of state programs subject to NEPA but approval of individual projects not subject to NEPA

- State EIA Requirements:

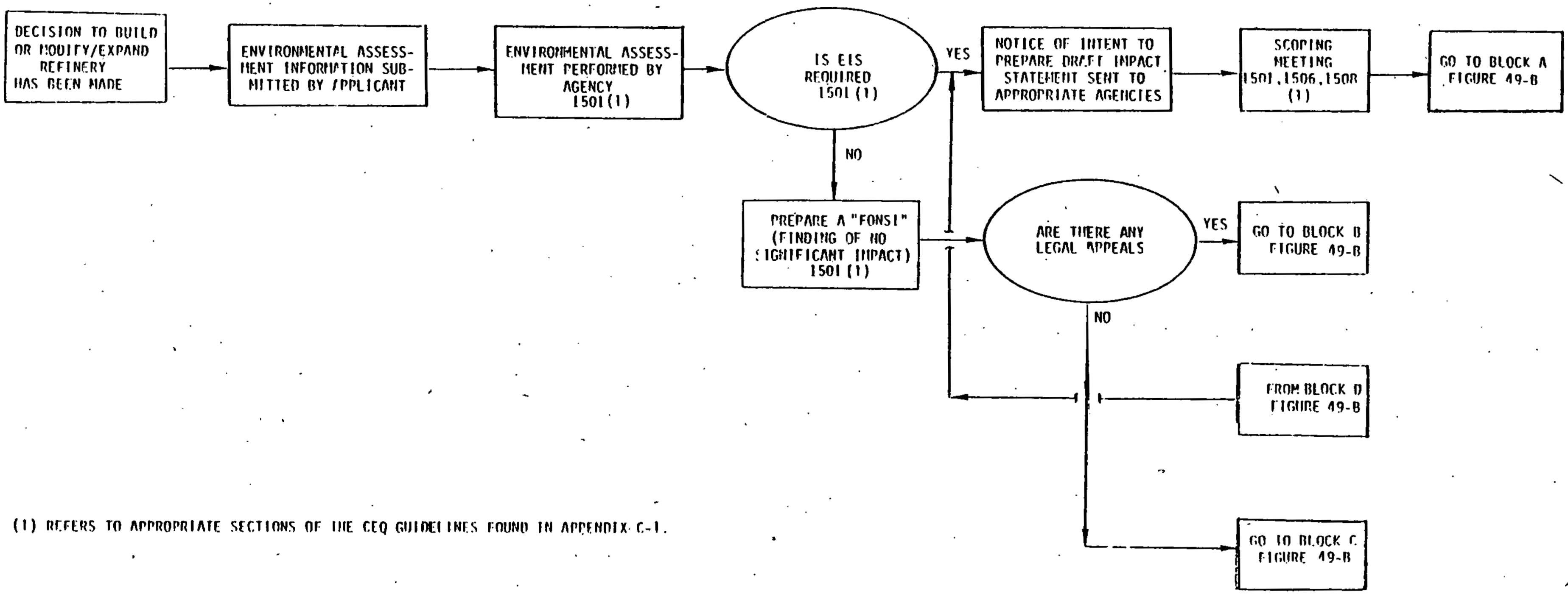
  Many states have adopted EIS requirements comparable to federal requirements under NEPA. As of 1978 these states are:

California	New Jersey
Connecticut	New York
Hawaii	North Carolina
Indiana	South Dakota
Maryland	Texas
Massachusetts	Utah
Michigan	Virginia
Minnesota	Washington
Montana	Wisconsin

- The open-ended nature of the environmental impact statement process makes it particularly significant to the planners of industrial projects. At a minimum, the determination that an EIS will be required will entail an extensive data-gathering effort and will subject a project to a full range of public examination. It will open up all aspects of an entire project to review and as successive questions are raised and answered may interpose substantial delays in the schedule for obtaining regulatory approvals. In addition, it may provide numerous grounds for judicial attack. Thus, where an EIS will be required, its implications upon schedule and viability must be recognized at the outset.

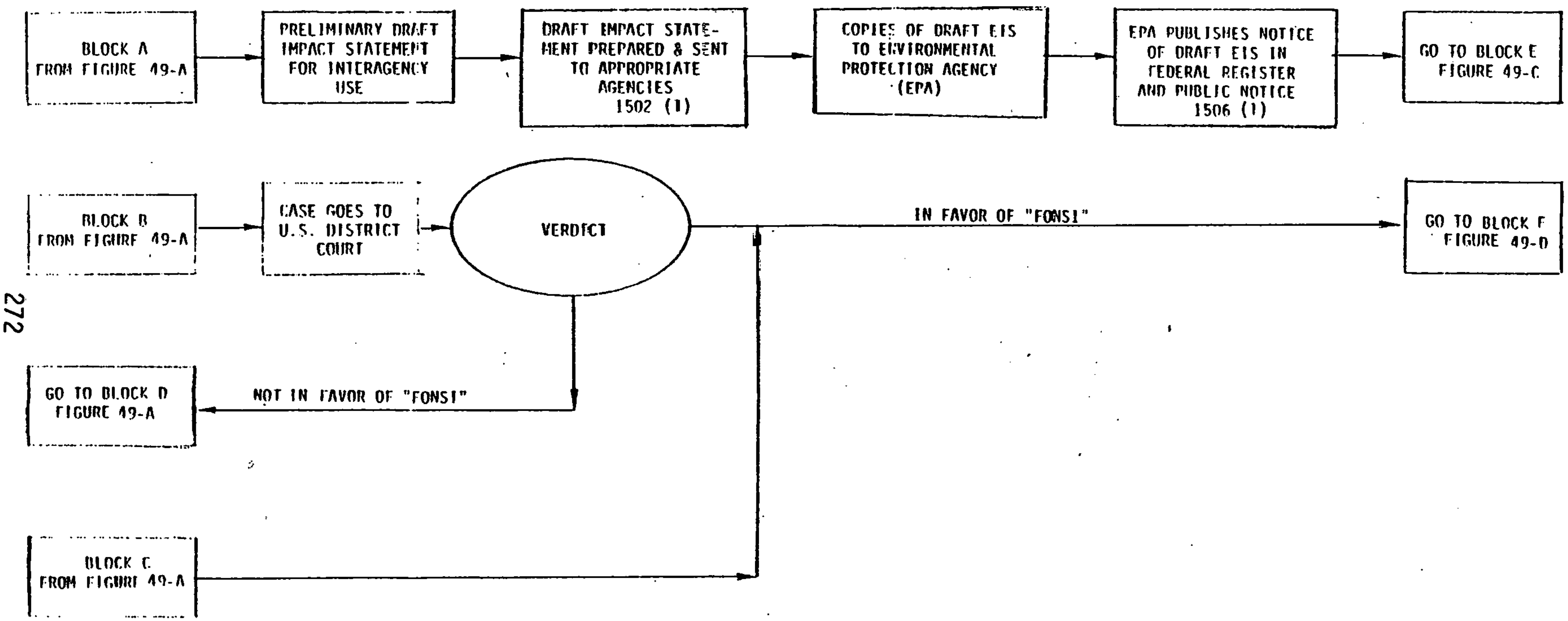
To summarize briefly the effect of the National Environmental Policy Act under the industrial siting process, a decision diagram has been developed and is shown in Figures 49 A-D. These figures show the assessment and impact statement review processes.

FIGURE 49A NATIONAL ENVIRONMENTAL POLICY ACT DECISION DIAGRAM



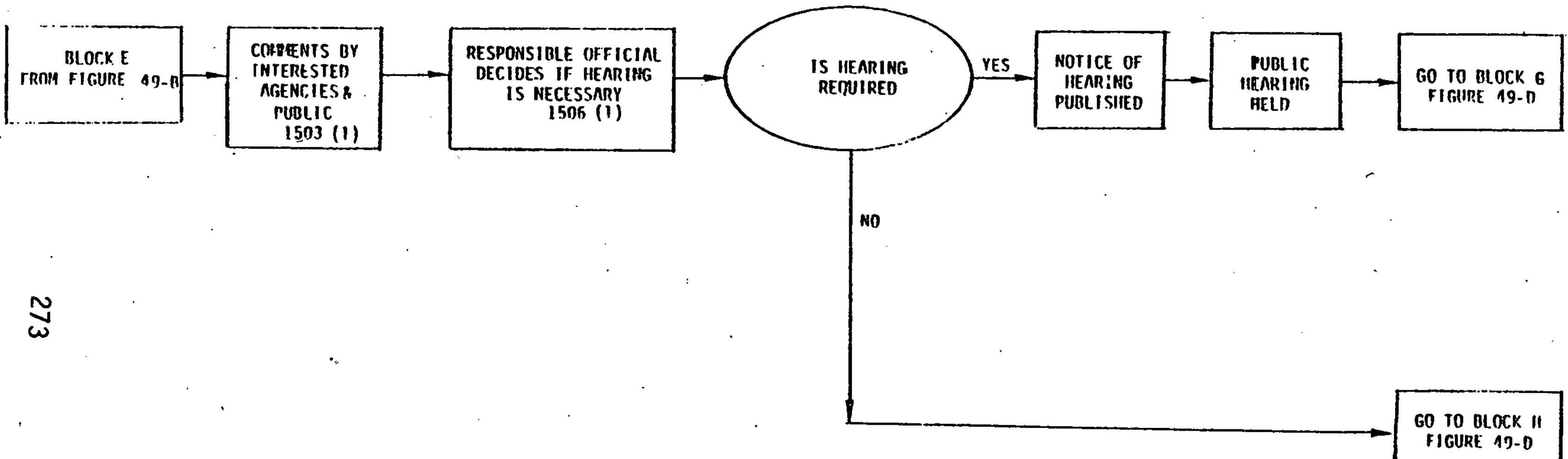
(1) REFERS TO APPROPRIATE SECTIONS OF THE CEQ GUIDELINES FOUND IN APPENDIX C-1.

FIGURE 49B NATIONAL ENVIRONMENTAL POLICY ACT DECISION DIAGRAM



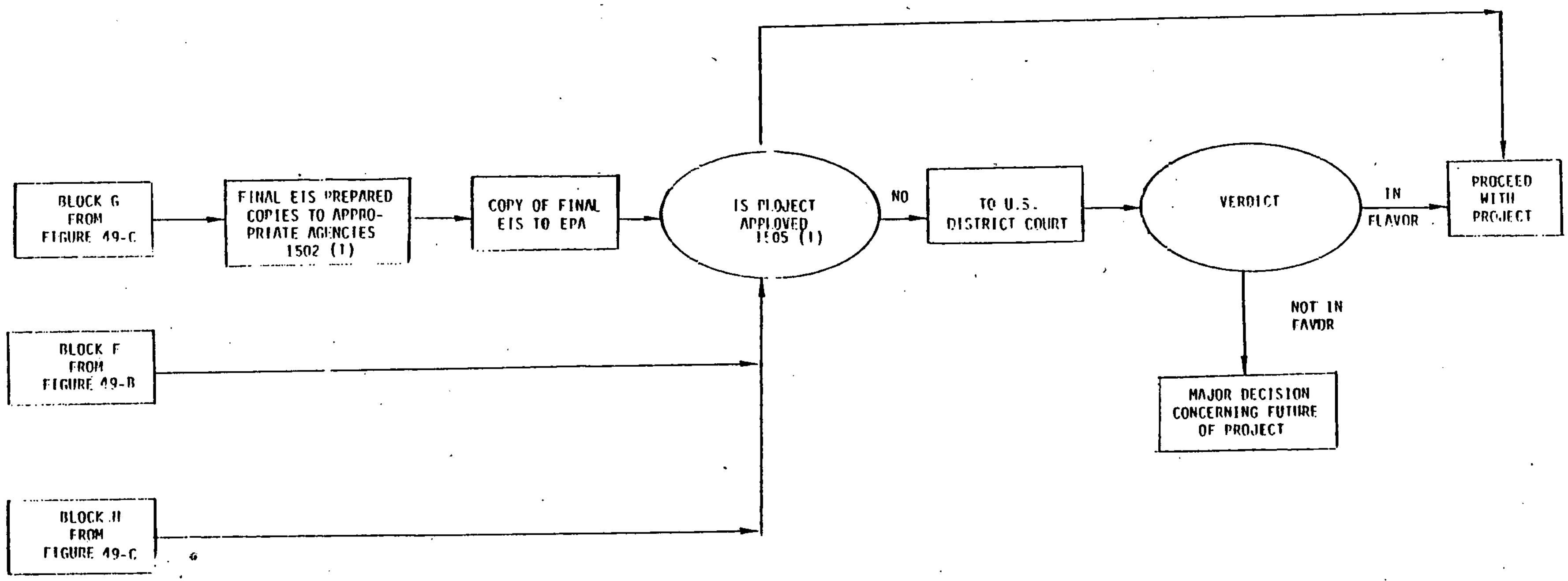
(1) REFERS TO APPROPRIATE SECTIONS IN THE CEQ GUIDELINES FOUND IN APPENDIX C-1.

FIGURE 49C NATIONAL ENVIRONMENTAL POLICY ACT DECISION DIAGRAM



(1) REFERS TO APPROPRIATE SECTIONS IN THE CEQ GUIDELINES FOUND IN APPENDIX C-1.

FIGURE 49D NATIONAL ENVIRONMENTAL POLICY ACT DECISION DIAGRAM



(1) REFERS TO APPROPRIATE SECTIONS IN THE CEQ GUIDELINES FOUND IN APPENDIX C-1

4.1.2 Introduction

On January 1, 1970, the National Environmental Policy Act (NEPA) was signed into law. Under this act, environmental considerations must be included in decision-making processes concerning federal projects and activities. Specifically, NEPA requires each federal agency to prepare a detailed statement of environmental impact before proceeding with any major action that may significantly affect the quality of the human environment. The Council of Environmental Quality has issued several sets of guidelines on how to prepare environmental impact statements, the most recent of which is effective July 30, 1979. A copy of NEPA and guidelines can be found in Appendix C-1 and C-2.

To determine if the action has a significant environmental impact, a careful examination must be made of the industrial process and the site location. It is important to know the types of emissions that will result from the proposed project in terms of air, water or hazardous waste, whether the amounts being emitted are significant and whether they are regulated by any federal, state or local standards. The existing conditions of the site should be examined to determine if there are special environmental constraints that will make compliance difficult. It will also be useful to know if siting a plant at this location was proposed by another firm and the types of obstacles they faced.

4.1.3 Environmental Impact Studies

It is important to understand the distinction between an Environment Assessment (EA) and an Environmental Impact Statement (EIS). An EA is a document describing the environmental impacts of a proposed action, and is prepared to determine whether or not an EIS is needed. The EA may be prepared by either the applicant or the government agency involved. However, before the government agency accepts the EA, it must take the responsibility for the accuracy of the contents of the EA. Some agencies refer to a document prepared by the applicant which is called an environmental report (ER). The ER is submitted to the agency and used in the preparation of an EA. An EIS is required under NEPA on any major federal action significantly affecting the human environment when federal funding is provided (in whole or part) or federal approvals or permits are required, unless the individual statutes provide for an exemption. The federal statutes most likely to affect environmental considerations are summarized in Table 36.

Furthermore, many states (in addition to some localities) have adopted ordinances which are comparable to the federal NEPA requirements. One must be careful to check if such requirements apply since content, timing, and consultation requirements may vary from the federal NEPA process.

4.1.4 Agency Consultation

At this point in the project development, the applicant has design information concerning the new refinery or major modification and has selected several potential sites. The applicant should be aware of the environmental constraints and be able to justify any significant impacts by mitigation of these impacts and/or demonstration of a need for this project both on an economic and energy basis. The early stages of project development should include a study of alternative industrial processes and alternative sites. This will assist the applicant in the final selection and will also demonstrate to the environmental agencies that environmental factors are seriously considered in the selection process. If these preparatory environmental studies are not conducted, the applicant risks the time and money spent on project development by having the selected site rejected.

The federal, state and local environmental officials should be consulted to make them aware of the project and also establish a line of communications. These officials should be asked to specify the exact permit requirements and the form of permit applications. It is particularly important to establish the field monitoring requirements since they will be one of the most costly and time consuming components of the process. The applicant may be able to get some indication as to the likelihood of

TABLE 36

PRINCIPAL FEDERAL ENVIRONMENTAL STATUTES AND
NEPA REQUIREMENTS

Statute	EIS Required	Exempt
Clean Water Act	For new sources only	All other sections of Act
Clean Air Act		All actions exempt
Coastal Zone Management Act	State program subject to NEPA	Individual projects exempt
Dredge and Fill Permits	COE permits subject to NEPA	
Fuel Use Act		Some actions exempt
Resource Conservation and Recovery Act	EPA permits for hazardous waste management facilities are subject to NEPA	

an EIS being required. It would be beneficial to request the agencies to review the government actions proposed by the applicant so that the level of NEPA review may be determined. This will allow the agency time to prepare an EA or EIS, if required.

4.1.5 EIS Guidelines

The Council of Environmental Quality (CEQ) has established uniform procedures for Federal implementation of the provisions of NEPA. These new procedures are intended to reduce paperwork, reduce delays and produce better decisions. The step-by-step preparation of an EIS under these new guidelines is shown in Figure 50. One of the important highlights of the regulations is the "scoping procedure," established to assist agencies in deciding what the central issues are, how long the EIS shall be and how the responsibility for the EIS will be allocated among the lead agency and cooperating agencies. The scoping process is to begin as early in the NEPA process as possible and integrated with other planning. The guidelines establish a recommended format for EIS's which allows a clear presentation of the alternatives of the proposed action. The standard format is shown in the following Table 37 and Appendix C-3 shows an actual EIS Table of Contents.

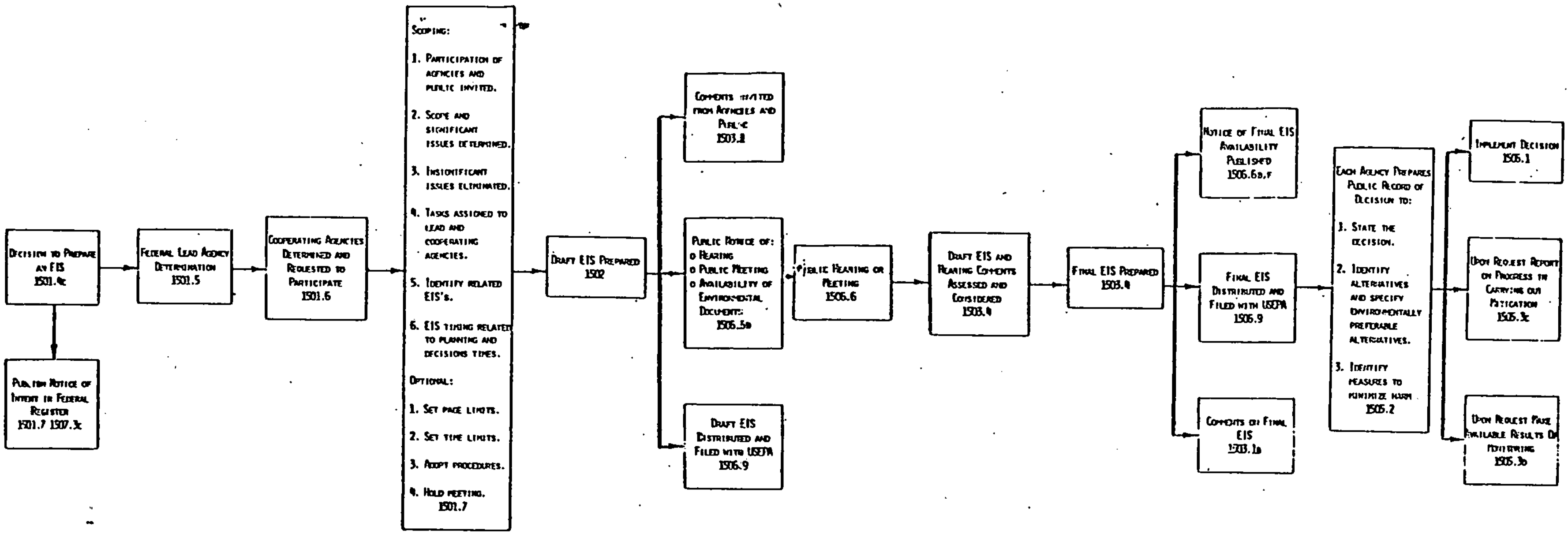
4.1.6 Processing of an EA/EIS

In those cases where a determination has been made that significant impacts may result from the federal action an EA is prepared. Once the EA has been prepared, one of the following conclusions can be drawn.

- The agency accepts the EA as an adequate assessment and determines that there are no significant impacts associated with the federal action related to the project. The agency then prepares a Finding of No Significant Impact (FONSI) which is a brief statement setting forth the agency's decision and the reasons for the negative determination. The EA is used as a support document.
- The agency determines that the EA is inadequate. It can then make the appropriate modifications and review the document again.
- The agency determines that there are significant impacts associated with the federal action related to the project and, therefore, decides to prepare a draft EIS (either in-house or using a consultant).

FIGURE 50

EIS PROCESS UNDER THE NEW CEQ GUIDELINES



Note: Numbers refer to appropriate sections of the July 30, 1978 CEQ Guidelines found in Appendix C-1.

TABLE 37

TYPICAL EIS OUTLINE

Summary (an executive summary of the EIS)

1. Project Description

    1.1 General Description

    1.2 Need for Proposed Facility

    1.3 Description of Property Acquisition

    1.4 The Proposed Plant

2. Project Alternatives

    2.1 No Build

    2.2 Site Alternatives

    2.3 Process Alternatives

    2.4 Treatment Alternatives

    2.5 Selection of Alternatives

3. Affected Environment

    3.1 General Description of Location in Region

    3.2 General Description of site location
    Land Use and Development
    Description of Receiving Water Body
    Public Facilities and Services
    The Cultural Resources
    Geology and Topography
    Demography
    Socio-Economic Profile
    Climatology
    Air Quality
    Hydrology
    Terrestrial Biota
    Aquatic Biota

TABLE 37 (Contd)

Environmental Impact of Proposed Action

4.1 Construction Impacts
Construction Plans
Land Use
Water Use
Air
Biota
Aesthetics
Erosion
Socio-Economic

4.2 Operational Impacts
Water Intake
Heat Dissipation System
Air Quality
Solid Waste Disposal
Ecological Impacts
Wastewater Discharge
Noise
Socio-Economic

4.3 Adverse Environmental Affects Which Cannot Be Avoided and Measures to Minimize Harm

Federal, State, Local and Other Sources From Which Comments Have Been Requested

Abbreviations Used

References

List of Prepares

Appendices

If an EA is determined to be inadequate, it is generally for one of the following reasons. Also shown are possible measures which could be used in the planning stages to assure an adequate EA.

- Analysis of one or more issues was inadequate - by consulting with the agencies ahead of time to determine their requirements, this problem can be minimized.

- Analysis of alternatives is insufficient - by involving as many of the potential parties as early as possibly the full range of alternatives is more likely to be considered.

- Environmental impacts are significant - The measures planned to mitigate environmental impacts by engineering considerations (pollution controls, selection of process, etc.) must be considered.

The draft EIS prepared by the lead federal agency will be circulated for review to federal, state, and local agencies and to interested individuals and public groups. A public hearing usually will be conducted.

After evaluating the comments from the review process, the agency will address substantive comments, issues and views brought to the agency's attention. These responses will be incorporated into final EIS. Copies of the final EIS, with attached review comments are sent to all reviewers who provided comments and to the USEPA.

Typical time periods for the steps of the NEPA process are as follows:

- Preparation of EA - 1.5 to 2 years depending on the extent of field programs.
- Review by federal agency - 3 to 6 months
- Preparation of draft EIS by federal agency - 4 to 6 months
- Public comment period between DEIS and FEIS - 3 months
- Preparation of final EIS - 3 to 6 months.

However, the refiner with his project's design in process must also coordinate this schedule with the permits discussed later. This scheduling of the NEPA process, permits, applications and project development is a complicated art and subject to reversals and problems.

4.1.7 Interaction with Permit Programs and Field Study Requirements

Both the length of, and costs associated with, the NEPA process are significantly affected by other permit processes that may apply to the project as well as the extent of field programs. These are discussed below.

- Air Quality

A variety of air regulations and permit requirements, discussed in Section 4.2, are currently in effect which will affect refinery siting, major modification or expansion. These include New Source Performance Standards (NSPS), Prevention of Significant Deterioration (PSD), and Emission Offset Policy-Nonattainment Regulations. The field program associated with these requirements can be extensive, generally on the order of one year. EPA has published guidelines on air quality monitoring programs that are fairly specific, but there is room for negotiation (e.g. for the number of monitoring sites). In addition, the computer modeling component of the analysis may vary significantly. It is therefore important to make early contact with the EPA (once the site has been established) as to the monitoring and modeling requirements. These programs can be time consuming, as one can see from Table 38 and costly. The general goal of EPA is to have the monitoring and modeling studies required for the air permit complete so the results can be incorporated into the NEPA process.

- Water Quality

Water quality sampling programs in connection with the National Pollutant Discharge Elimination System (NPDES) permit program can vary widely with respect to time and cost. Time and cost are a function of the number of years of sampling, number of sampling points, number and kind of parameters to be measured, etc. Typical monitoring programs can include several years of pre-construction monitoring, construction period monitoring, and several years of post-construction (operational) monitoring. With respect to the NEPA process, one year of data has generally been sufficient in order to evaluate the potential environmental impacts of the project.

TABLE 38

TIME REQUIRED FOR NEW SOURCE REVIEW PERMIT ISSUANCE WITH ONE-YEAR MONITORING PROGRAM

Activity	Time for Activity (Months)	Cumulative Time (Months)
Specify monitoring required	1-2	1-2
Select vendors and contractors	0-3	1-5
Procure and install equipment	1-4	2-9
Conduct 1-yr baseline monitoring	12	14-21
Complete data analysis, modeling and permit application	1-4	15-25
Request special model (if necessary) with agency hearing and review	0-6	15-31
Hearings on application and agency review	3-12	18-43

Source: Pollution Engineering Yearbook and Product Reference Guide, 1979

- Biology

Biological programs (e.g. 316 a & b studies) can also be as lengthy (pre-, during, and post-construction monitoring) and vary significantly with locale, species present, number of samples, etc. Again one year of monitoring data has generally been sufficient for NEPA purposes. These actual monitoring requirements with respect to both water quality and biological programs can vary significantly from one EPA region to another and from one state to another.

Consultation with the Corps of Engineers about projects involving wetlands (Section 404) and dredge and fill (Section 10) activities is also required. The Corps further consults with the U. S. Fish and Wildlife Service. Studies in this area are again subject to great variance depending on local conditions and the agencies involved. One year is generally sufficient for NEPA purposes.

- Other Field Programs

The other programs of concern are noise and cultural resource analyses. These studies are much less complicated and costly than the field programs described previously. They can easily be done within the NEPA timeframe. With respect to cultural resources, consultation with the State Historic Preservation Officer is important to identify resources and sensitive areas and to scope any field studies.

4.1.3 Public Participation

The applicant should establish a public awareness program as a part of the early stage project development. At the same time, the applicant consults with federal, state and local agencies, a similar effort should be initiated with local government groups and interested organizations. The publics awareness of the project is affected by the demonstrated need for the action and the expected benefits to the local community (economic and energy). It is important to secure general acceptance and support for the proposed action, early on in the NEPA process, before the completion of the EA or draft EIS document.

Methods to increase public participation and acceptance are public hearings; informal public meetings, advisory groups of private citizens, public interest groups and public officials. The beginning of public awareness is a presentation that describes the proposed action, potential impacts and proposed mitigation and economic and energy benefits.

4.2 THE CLEAN AIR ACT (CAA)

4.2.1 Summary

- National Ambient Air Quality Standards (NAAQS) promulgated by EPA specify maximum concentrations of pollutants legally permissible anywhere in the country. The pollutants of concern are: particulates, sulfur dioxide, lead, photochemical oxidants (ozone), hydrocarbons, carbon monoxide, and nitrogen dioxide. The principal NAAQS were set in 1971.

- State Implementation Plans (SIPs) developed by the states and approved by EPA contain the actual abatement requirements devised to reduce air pollution as necessary to achieve compliance with the NAAQS.

- Revision of SIPs: The 1977 Amendments of the CAA require each state to revise the SIP for all nonattainment areas, tightening abatement requirements so as to assure attainment of full compliance by 1982; a further extension to 1987 is allowed photochemical oxidants and carbon monoxide, under certain conditions; unless SIP revisions are submitted by state and approved by EPA prior to July 1, 1979, new sources may not be constructed in such areas after that date until the plan is approved. Since many SIPs are currently being revised, care must be used to verify current applicable SIP.

- Industries emitting asbestos, beryllium, mercury, or vinyl chloride are subject to special regulations under national emission standards for hazardous air pollution (NESHAPA).

- New source performance standards would apply to a new refinery and an expansion; the regulations currently issued and proposed should be checked.

- Prevention of Significant Deterioration (PSD)
  A regulatory program requiring preconstruction approval of new plants with significant potential emissions to be built in clean air areas.

- Chief components of the PSD program:

  1. Area classification system -- all areas in the country meeting air quality standards classified Class I, Class II, or Class III with varying limitations on growth in each class.

  2. Increments of air quality -- numerical limitations restrict increases of pollution above existing baseline concentrations.

3. BACT -- all large plants under PSD must install best available control technology (determined on a case-by-case basis).

4. Preconstruction approval -- detailed requirements, data analyses, and public hearings.

- Plants subject to PSD: new plants or expansions located in any area where air quality standards are being met and if potential emissions of any regulated pollutant exceed 100 tons per year for plants within 28 specified industrial categories or if potential emissions exceed 250 tons per year for any other plant.

- Two-tiered PSD review: Sources subject to PSD but with actual emissions not exceeding 50 tons per year, 1000 pounds per day, or 100 pounds per hour qualify for a simplified review, omitting requirements to demonstrate compliance with increment and to install BACT.

- NONATTAINMENT: In any area where any ambient air quality standard is being violated, no major new source, such as a refinery, can be constructed without a permit.

- Nonattainment Sources: Sources subject to nonattainment requirements include any new plant (or expansion) with potential emissions equal to or greater than 100 tons per year of particulates, SO_2, NO_x, volatile organic compounds, or carbon monoxide.

- Two-Tiered Nonattainment Review: Sources subject to nonattainment but with actual emission not exceeding 50 tons per year, 1000 pounds per day, or 100 pounds per hour qualify for a simplified review, omitting requirements of offsets and LAER.

- Chief Components of Nonattainment Review:

  1. Offsets - Enforceable reductions in existing sources of pollution which exceed the projected emissions from the proposed facility.

  2. LAER - Lowest achievable emission rate.

  3. Other sources within the state in compliance.

  4. Applicable SIP is being carried out.

  5. Provide public review and hearings.

- PSD-NONATTAINMENT Overlap: A new refinery or either an expansion or modification of an existing refinery can be subject to both PSD and nonattainment review if:

1. The project is located in a PSD for one set of pollutants and nonattainment for other pollutants, or

2. The emissions from a project located in a PSD area causes an impact on a nonattainment area or vice versa.

- Civil Suits - Section 304 of the Clean Air Act provides enforcement by civil units. These suits which can be filed by any person can be against an emitter, the administrator, or any government agency.

- Judicial Review - Because of the importance and sometimes the controversial nature of EPA's decisions concerning the Clean Air Act, some decisions are challenged in the Court of Appeals for the District of Columbia. The PSD regulations (40 CFR 51.24 and 52.21) are undergoing judicial review as of this writing. The results of this case will invalidate major portions of this PSD program.

To summarize the Clean Air Act upon the siting process for a new refinery, a decision diagram has been developed and is shown in Figures 51-53 These figures show the regulatory considerations and impacts faced by a potential new source. This same decision process on the regulatory impacts for major modifications or expansions are presented in Figures 54-56. These requirements are discussed in the next chapter.

FIGURE 51 CLEAN AIR ACT DECISION DIAGRAM FOR NEW REFINERY

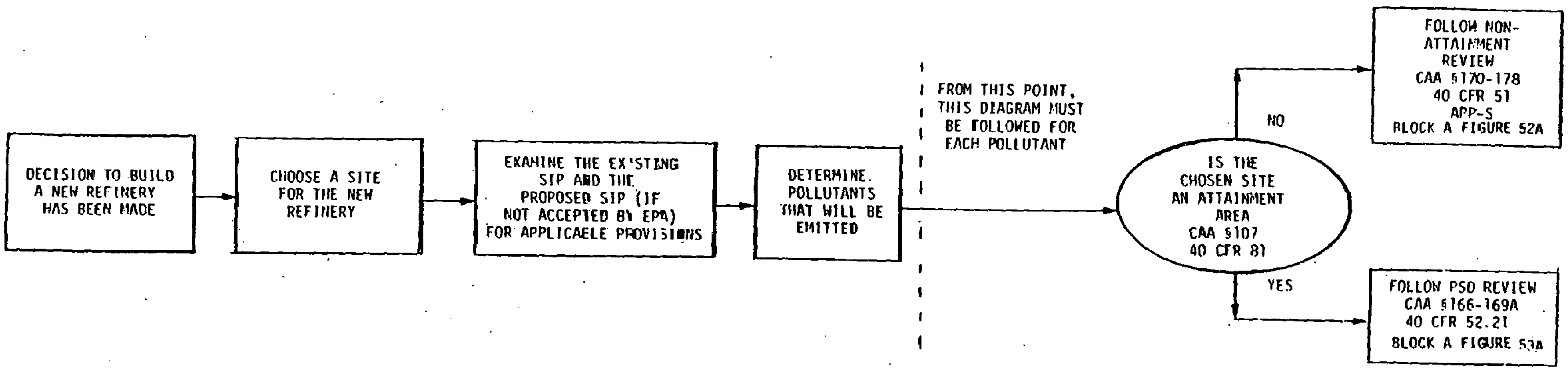


FIGURE 52A CLEAN AIR ACT - NON-ATTAINMENT REVIEW DECISION DIAGRAM FOR NEW REFINERIES

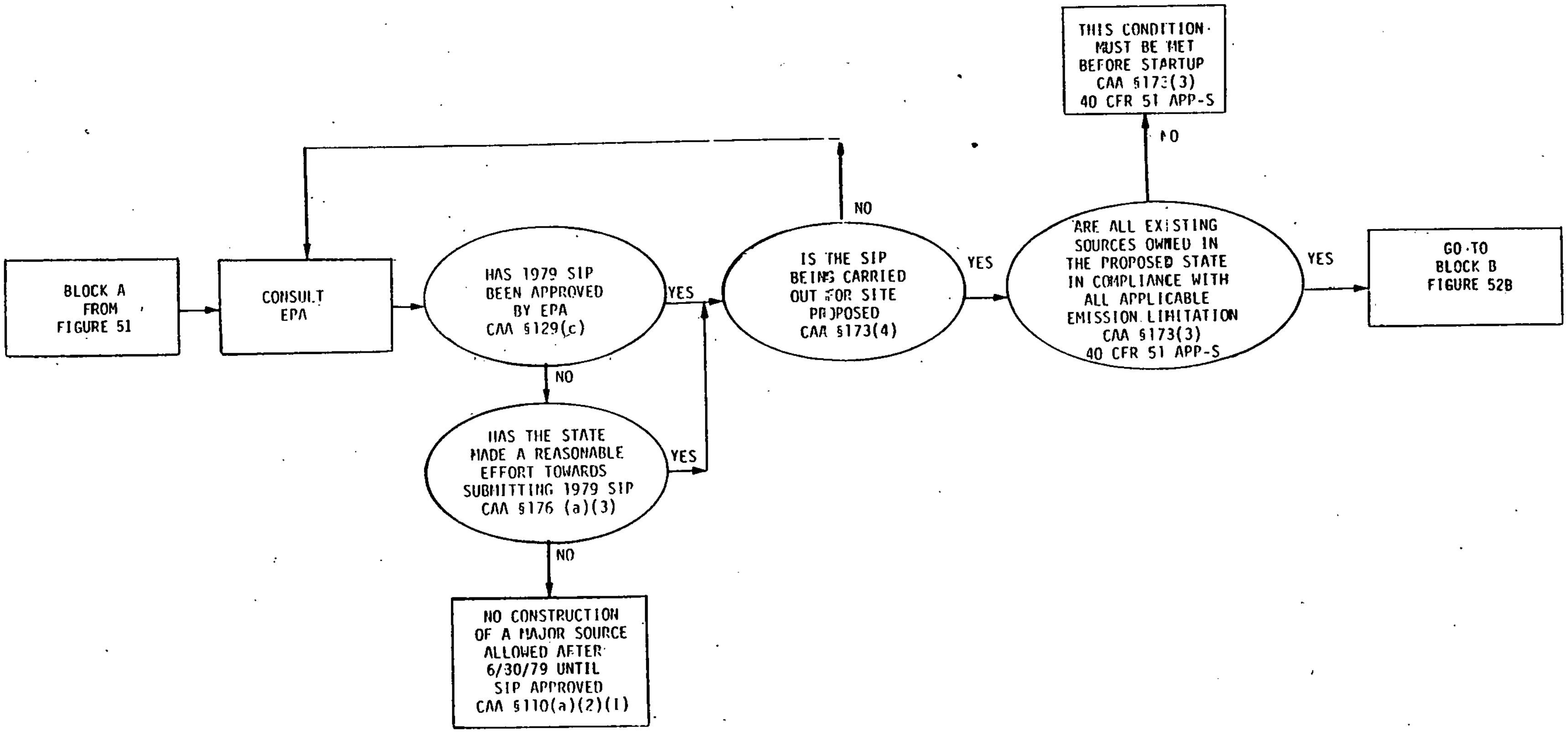


FIGURE 52B CLEAN AIR ACT - NON-ATTAINMENT REVIEW DECISION DIAGRAM
FOR NEW REFINERIES

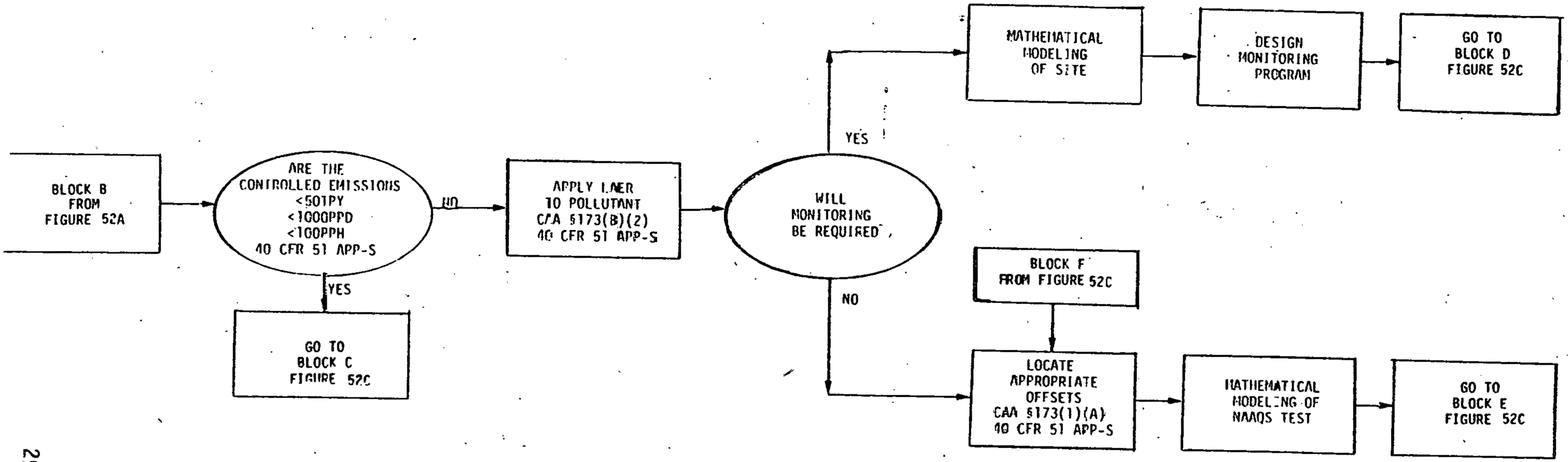


FIGURE 52C CLEAN AIR ACT - NON-ATTAINMENT REVIEW DECISION DIAGRAM FOR NEW REFINERIES

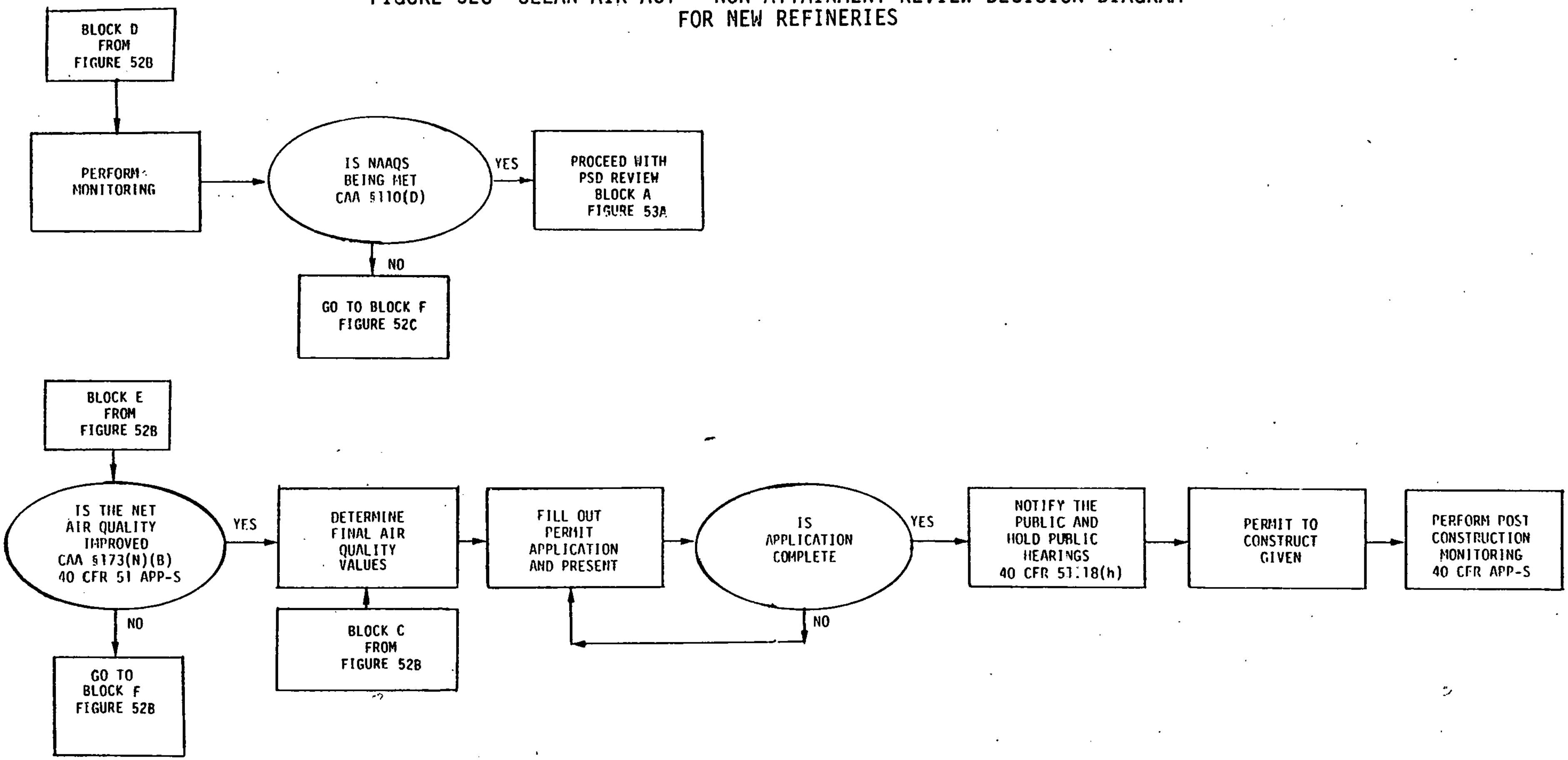


FIGURE 53A CLEAN AIR ACT - PSD REVIEW DECISION DIAGRAM FOR NEW REFINERIES

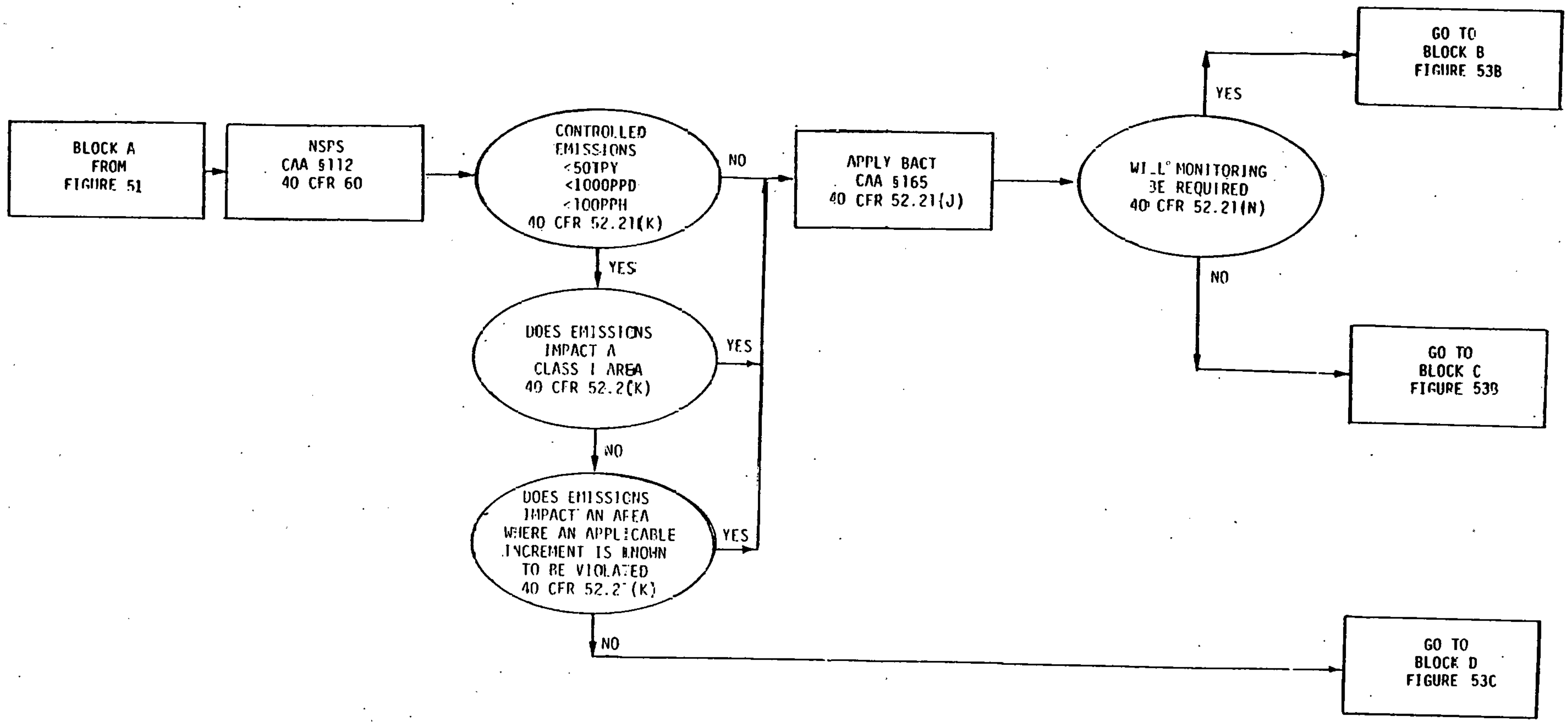


FIGURE 53B CLEAN AIR ACT - PSD REVIEW DECISION DIAGRAM
FOR NEW REFINERIES

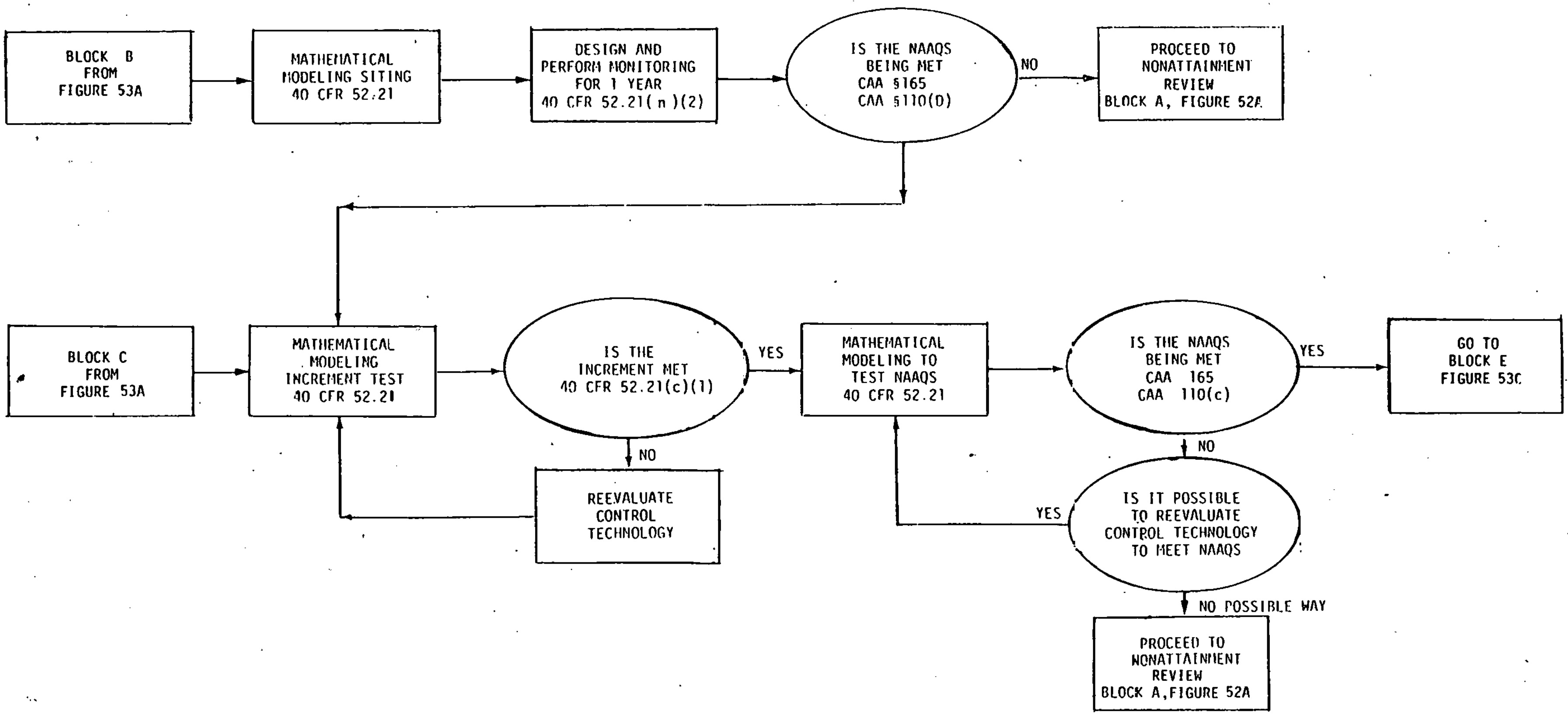


FIGURE 54C CLEAN AIR ACT - PSD REVIEW DECISION DIAGRAM
FOR NEW REFINERIES

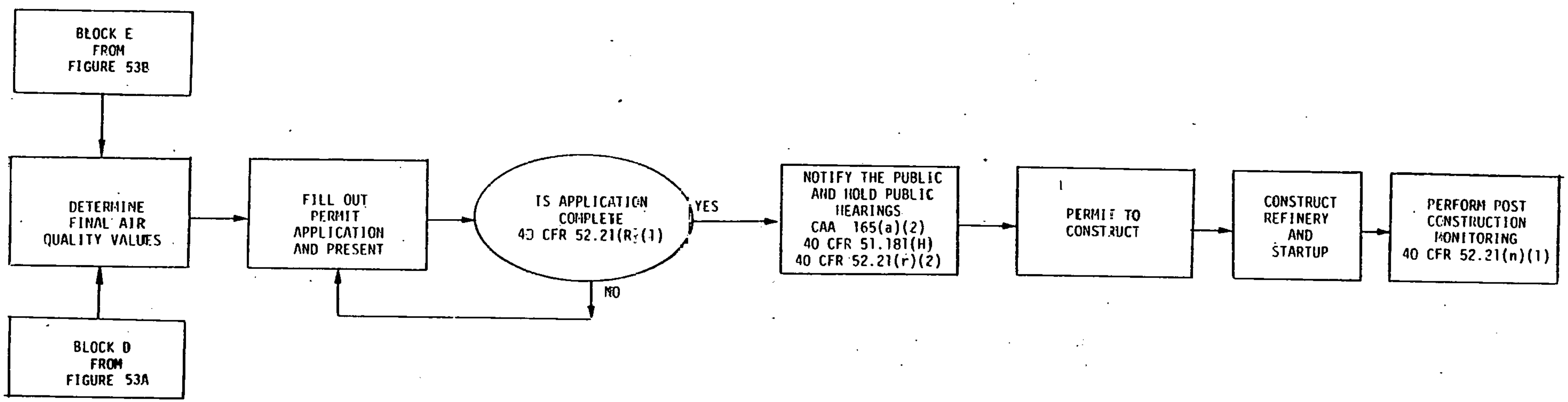


FIGURE 54 CLEAN AIR ACT DECISION DIAGRAM FOR EXPANSION/MODIFICATION OF A REFINERY

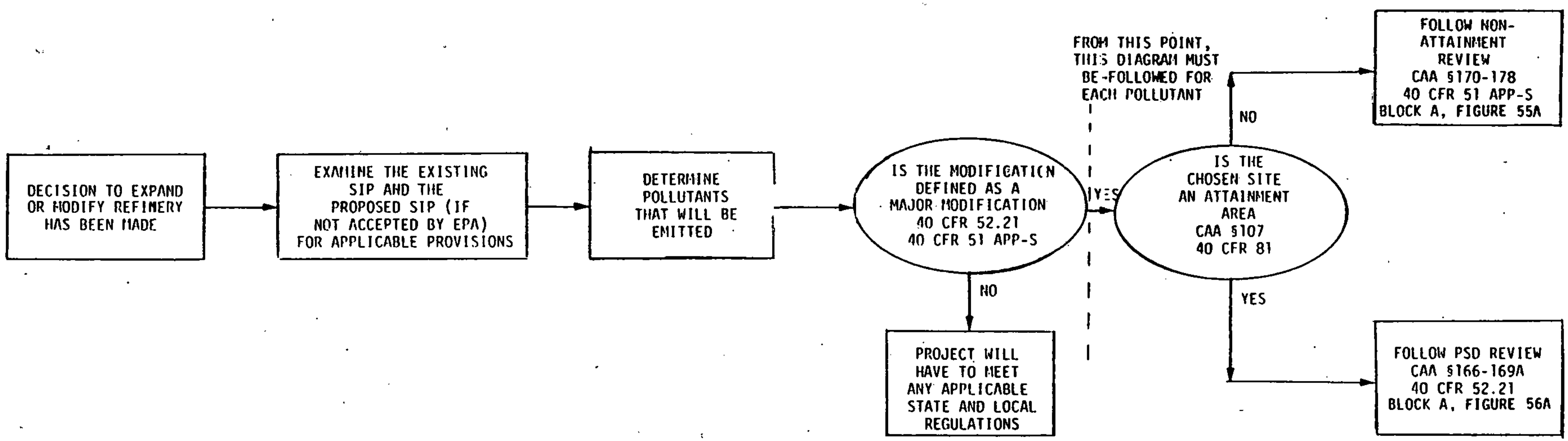


FIGURE 55A CLEAN AIR ACT - NON-ATTAINMENT REVIEW DECISION DIAGRAM
FOR EXPANSION/MODIFICATION OF A REFINERY

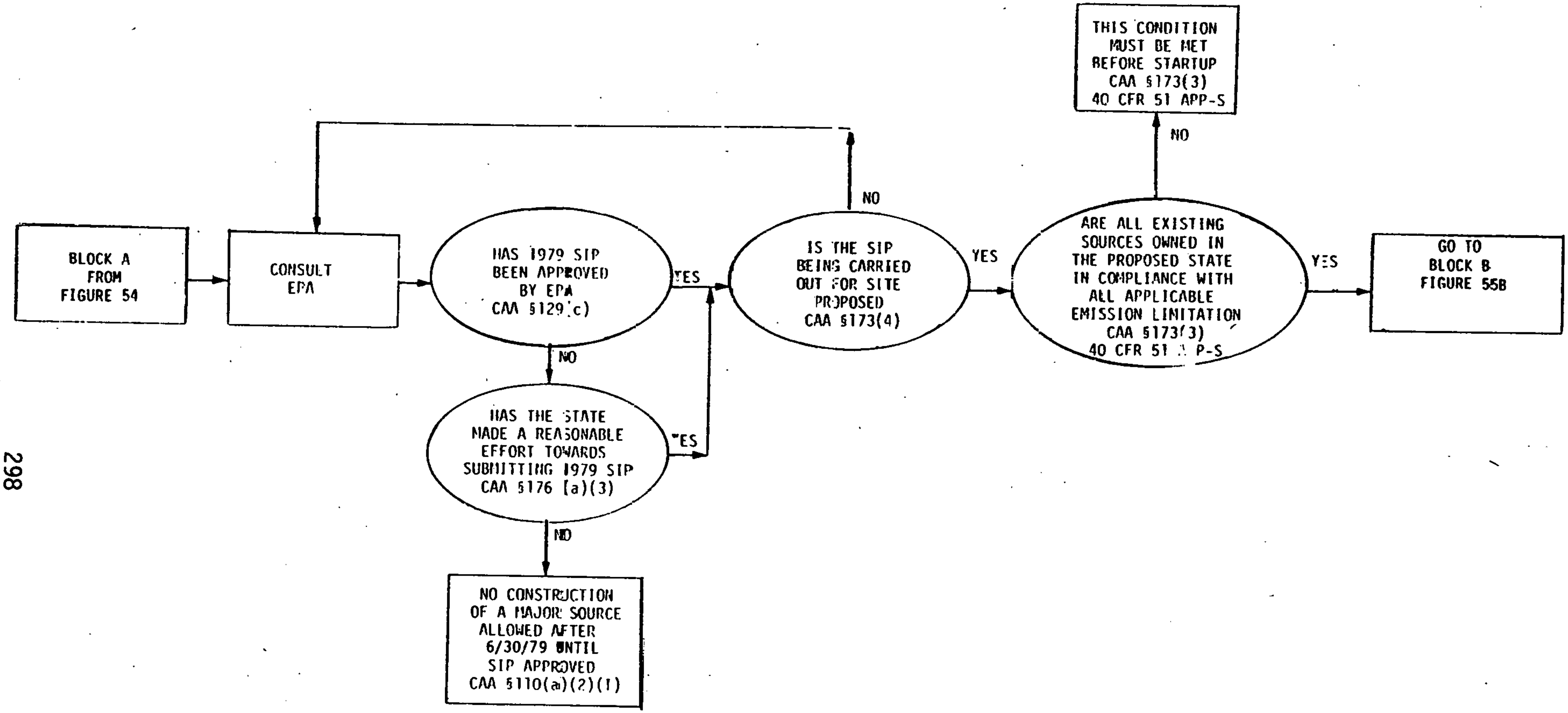


FIGURE 55B CLEAN AIR ACT - NON-ATTAINMENT REVIEW DECISION DIAGRAM FOR EXPANSION/MODIFICATION OF A REFINERY

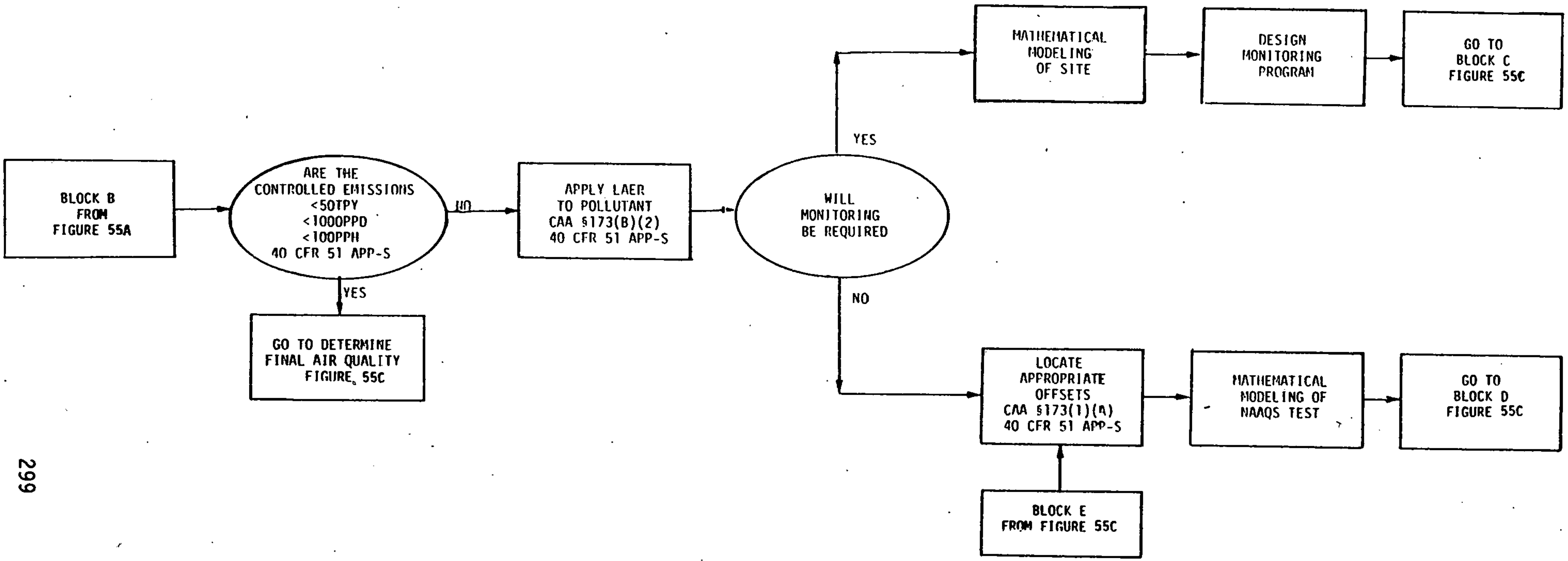


FIGURE 55C CLEAN AIR ACT - NON-ATTAINMENT REVIEW DECISION DIAGRAM FOR EXPANSION/MODIFICATION OF A REFINERY

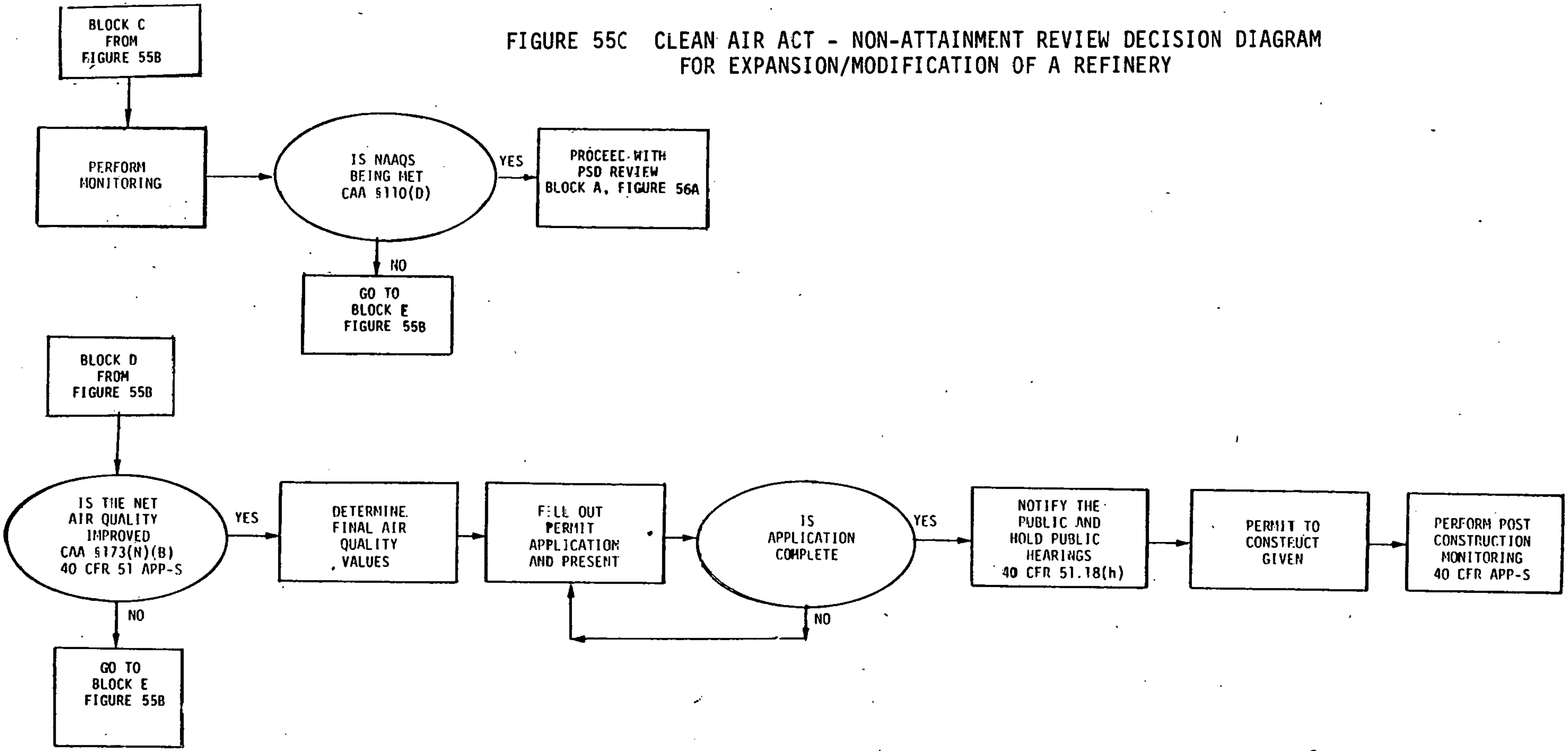


FIGURE 56A CLEAN AIR ACT - PSD REVIEW DECISION DIAGRAM FOR EXPANSION/MODIFICATION OF A REFINERY

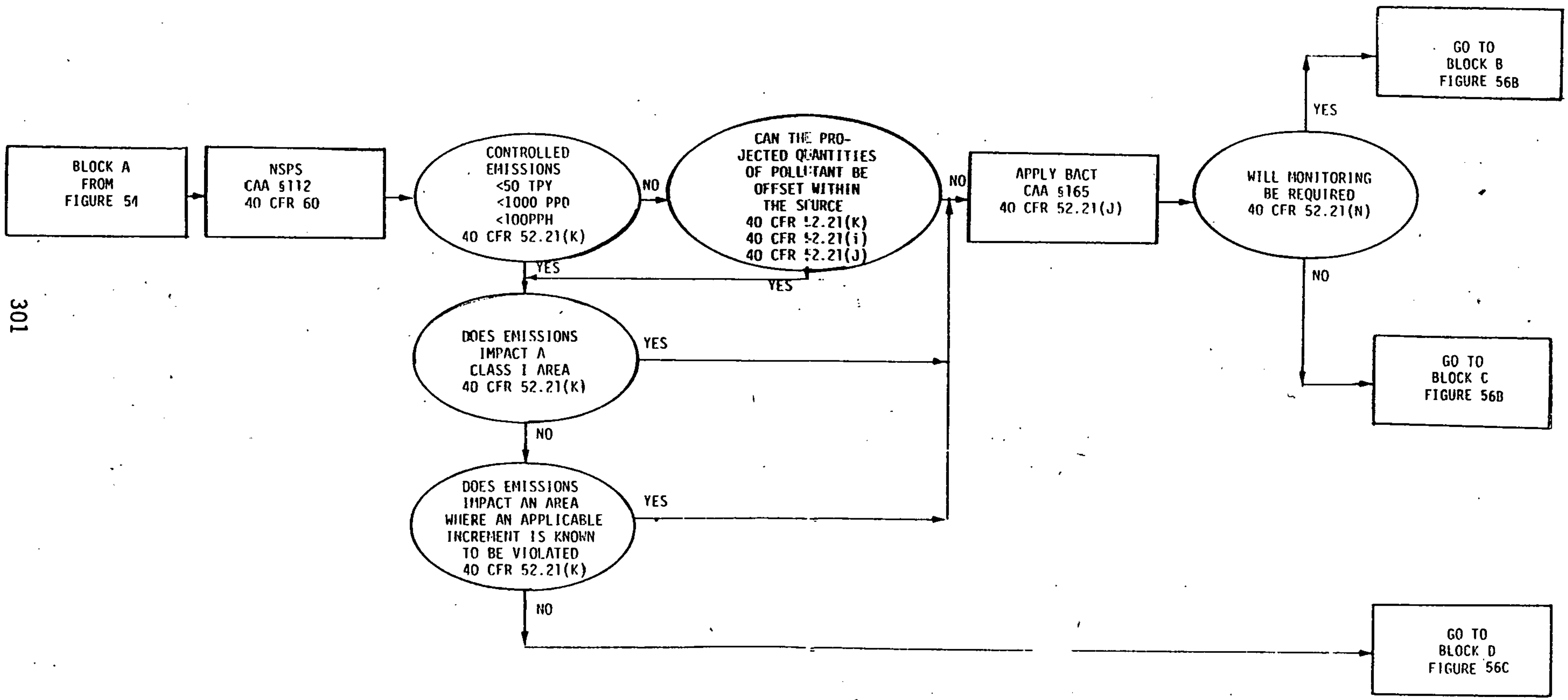


FIGURE 56B CLEAN AIR ACT - PSD REVIEW DECISION DIAGRAM
FOR EXPANSION/MODIFICATION OF A REFINERY

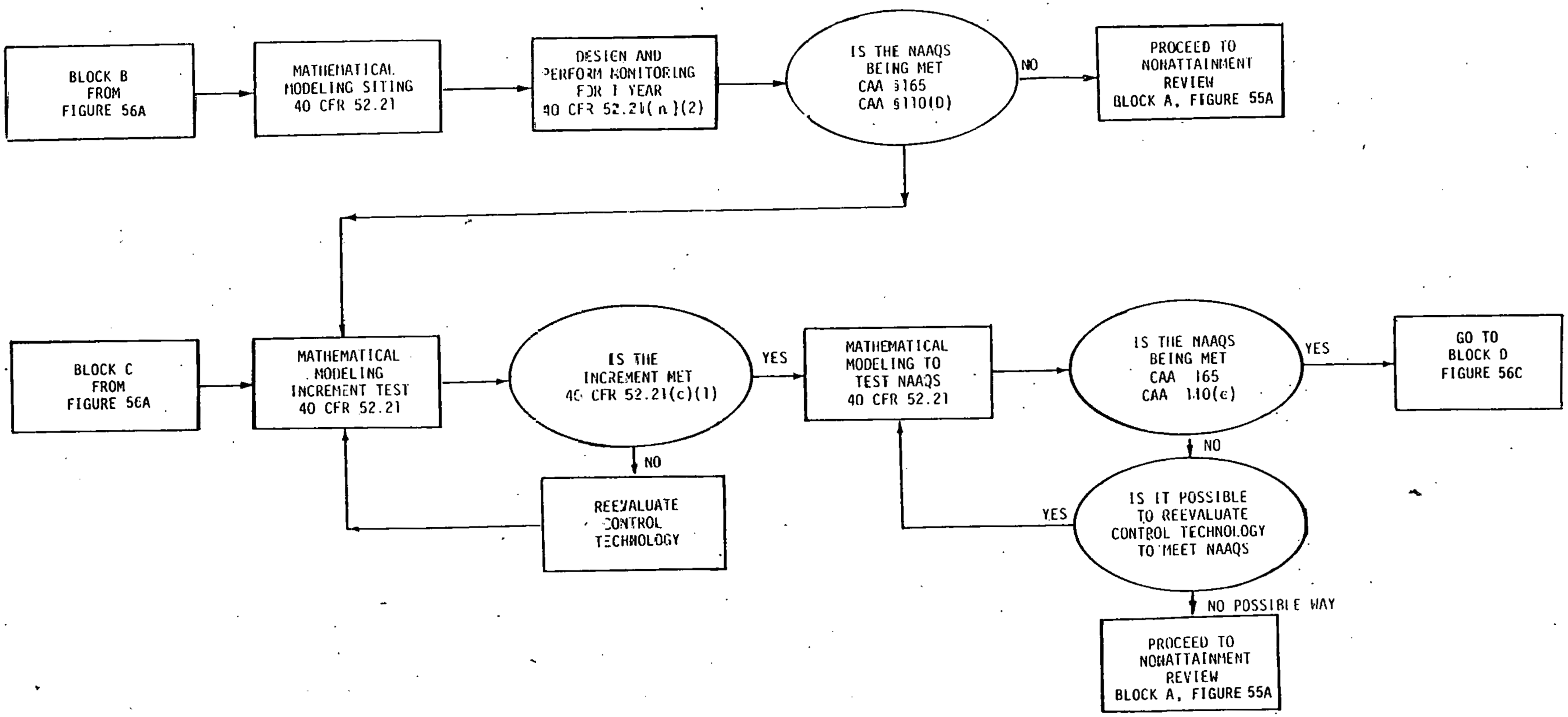
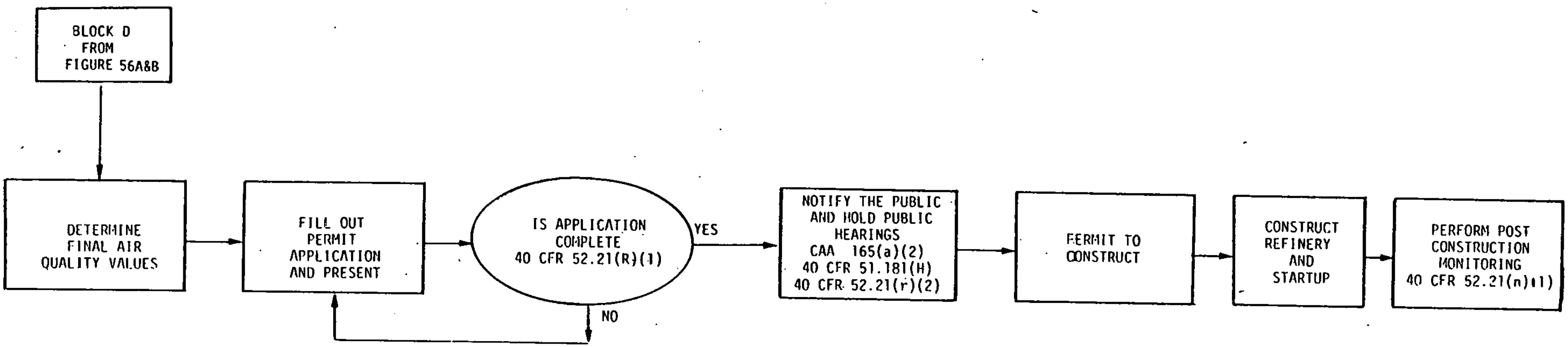


FIGURE 56C CLEAN AIR ACT - PSD REVIEW DECISION DIAGRAM FOR EXPANSION/MODIFICATION OF A REFINERY



4.2.2 Introduction

The first act which addressed air pollution was passed in 1955, "Air Pollution Control Research and Technical Assistance Act," Public Law 84-159. It was amended in 1963 and gave the federal government regulatory authority concerning air pollution. The basic statutory framework now in effect was established by the Clean Air Act of 1970, Public Law 91-604. Congress amended the 1970 Act in 1974 to deal with energy-related questions and again in 1977 (P.L. 95-95) when a number of amendments were adopted with particularly important provisions concerning approval of new industrial plants or, as in this case, a new refinery or expansion of an existing facility.

Although the complexity of the Clean Air Act deserves full discussion, it would be very lengthy, complicated, and subject to change due to the Alabama Power Company Court decision which invalidated major sections of the amendments. A copy of the Clean Air Act with the 1977 amendments and the Alabama Power Company decision can be found in Appendix D-1 and D-2. Certain essential features of the statutory framework must be recognized in order to understand the manner in which the Clean Air Act afffects approval of new refineries or expansion of an existing refinery.

4.2.3 National Ambient Air Quality Standards

The Clean Air Act was built on the concept of achieving specified National Ambient Quality Standards (NAAQS). The standards define the quality of air which must be achieved to prevent adverse health effects. Many critical features of the program originate from this foundation - including the basic point that control requirements depend on adequate data and analysis, to determine what the air quality actually is, to identify the sources of pollution affecting air quality and the manner in which pollutants are dispersed and interact in the ambient air, and to determine what reductions and controls are needed to achieve specified air quality objectives.

The principal standards are called primary air quality standards. These are based on health, and specify the levels of pollution which cannot be exceeded without threatening adverse effects on human health. Another set of standards, the secondary air quality standards, set limits on concentrations of pollution that cannot be exceeded without adverse effects on public welfare (vegetation, property damage, scenic value, etc.)

A basic feature of the clean air program is that air quality standards are issued for individual pollutants, and the regulatory controls therefore are tied to the individual pollutants. In a sense, the Clean Air Act establishes not one regulatory program but several, a separate program for each pollutant for which standards have been established.

Another significant factor arises out of the concept that the air quality standards are designed to prevent adverse effects. Scientific observations have indicated that in some cases adverse effects occur in response to brief exposures to high levels of pollution, whereas other types of damage may result from long-term exposures to lower levels of pollution. For this reason, most of the air quality standards specify two types of limitations -- long-term standards which cannot be exceeded on an annual average, and short-term standards which cannot be exceeded for periods such as 3 hours or 24 hours.

EPA promulgated the basic set of current standards in April 1971. These covered the following pollutants: particulates, sulfur dioxide, photochemical oxidants (ozone), hydrocarbons (a precursor to photochemical oxidants), carbon monoxide, and nitrogen oxides. In 1978, EPA promulgated NAAQS for lead, and in 1979 revised the standard for ozone. See Tables 39 and 40.

The basic ambient air quality standards upon which the current state implementation plans were based on are shown in Tables 39 and 40. The annual standard is applied as a mean (though frequently referred to as an annual average"), while the short-term standards are applied as maximum concentrations, over the period indicated, not to be exceeded more than once per year. For additional information, refer to 40 CFR 50 in Appendix D-3.

TABLE 39

NATIONAL AMBIENT AIR QUALITY STANDARDS

Primary Standards

ug/m^3 *

Pollutant	Annual Standard	Short-Term Standard
Sulfur Dioxide	80	365 (24 hrs.)
Particulates	75	260 (24 hrs.)
Carbon Monxide	--	10,000 (8 hrs.) 40,000 (1 hr.)
Ozone	--	235 (1 hr.)
Hydrocarbons	--	160 (3 hrs. - 6-9 a.m.)
Nitrogen Dioxide	100	--
Lead	1.5 (3 months)	--

* Micro-grams for cubic meter.

TABLE 40

NATIONAL AMBIENT AIR QUALITY STANDARDS

Secondary Standards

ug/m³*

Pollutant	Annual Standard	Short-Term Standard	
Sulfur Dioxide	--	1300	(3 hrs)
Particulates	60	150	(24 hrs.)
Carbon Monoxide	--	10,000	(8 hrs.)
		40,000	(1 hr.)
Ozone	--	235	(1 hr.)
Hydrocarbons	--	160	(3 hrs. - 6-9 a.m.)
Nitrogen Dioxide	100	--	
Lead	1.5 (3 months)	--	

* Micro-grams per cubic meter.

Congress, in revising the Clean Air Act, ordered EPA to review and, if necessary, revise ambient air quality standards by the end of 1980 and every five years after that. EPA is in the process of reviewing and are considering combining the criteria documents for sulfur oxides and particulates. A copy of the review may be available after April, 1980.

4.2.4 State Implementation Plans

Following establishment by EPA of the air quality standards, the Clean Air Act directed state agencies and local government to develop and adopt state implementation plans (SIPs) setting forth all of the necessary control efforts to achieve compliance with the NAAQS. The EPA set up guidelines to assist the states in developing their SIP program. The front page of these guidelines, 40 CFR 51, can be found in Appendix D-4.

The statute sets a strict time schedule for both adoption and implementation of the plans. States were required to submit plans to EPA within nine months after promulgation of the air quality standards, and final plans had to be approved or promulgated by EPA within six months thereafter, or not later than July 31, 1972. The law required that the plans assure attainment of the air quality standards within three years, subject to a two-year extension under certain condition, thereby establishing an ultimate statutory deadline for achievement of the air quality standards by July 31, 1977.

Section 110 of the Act required that the state plan include a construction permit program for any major emitting facility to assure that the national ambient air quality standards are achieved and maintained. The permit program is discussed in detail in another section of this report.

To provide basic geographic units for the air pollution control program, the country was divided into 247 air quality control regions (AQCRs). The air quality in each region can be found in 40 CFR 81 located in Appendix D-5. Decisions as to the amount of control required in individuals AQCRs were based on available air quality data, often utilizing an oversimplified approach of making a single computation for an entire region. Under a standard rollback approach, the total quantity of pollution in a region was estimated, the quantity of pollution which could be tolerated without exceeding standards was then amount of control required in individual AQCRs were based on available air quality data, often utilizing an oversimplified approach of making a single computation for an entire region. Under a standard rollback approach, the total quantity of pollution in a region was estimated, the quantity of pollution which could be tolerated without exceeding standards was then calculated, and a determination based on the differential as to the degree of reduction required. The implementation plan was then drafted to produce a combination of control efforts which would yield an overall reduction sufficient to cover that need. Inevitably this approach meant that in some parts within an AQCR excessive controls might be required while in other parts the requirements might be inadequate. Further deficiencies crept in if the original data base was unsound, if the inventory of existing sources was incomplete, or if other mistakes were made in the technical determinations.

As better information has been collected and more experience acquired, the need to revise the original state implementation plans became apparent. Consequently, Congress in its 1977 Amendments imposed more demanding provisions in the SIP program.

In the 1977 Amendments, the original requirements were retained and several others added. By August 7, 1978, each state must submit a SIP revision that required each major source to pay fees to cover the state's costs of handling any construction or operating permit for the source, require state permit and enforcements boards to restructure their memberships and make public disclosures to prevent conflicts of interest, provide for prevention of interference with other state's air quality, require consultation with local governments and federal land managers in carrying out major SIP functions, and provide for notification to the public of areas not meeting the NAAQS.

The most significant addition to the SIP process adopted by the 1977 Amendments relates to areas that did not achieve the NAAQS within the statutory deadlines, so called "non attainment areas." Although much attention has been directed toward the provisions applicable to new sources

... non-attainment areas", discussed below, along with the SIP provisions applicable to review new sources in clean air areas to "prevent significant deterioration" of air quality, also discussed below, the 1977 Amendments also imposed additional SIP requirements on existing sources.

In addition to the significant new source review provisions, "all" existing sources must be required to install, at a minimum, "reasonably available control technology." States must also show "reasonable further progress" toward achievement of the NAAQS, which is defined in Section 171 of the Act as the accomplishment of "annual incremental reductions in emissions." As an "incentive" to States to adopt these more stringent provisions, Congress provided that if revised SIP provisions are not adopted and approved by EPA by June 30, 1979, there can be no construction in the State of new or modified sources of the air pollutants for which NAAQS are exceeded.

Currently, 41 states have submitted SIPs to the EPA and only two plans have been "completely" approved. One problem that has caused a lot of the plans not being approved but should not have effect on new refining or expansion, is the vehicle inspection and maintenance control program which must be included in the SIP program. For the status of each state implementation plan as of January 28, 1980, see Table 41.

In the meantime, the existing implementation plans remain in effect. They contain a variety of control requirements, which apply generally to nearly any source of pollution, both those in existence at the time of their adoption and those thereafter constructed. Therefore, the first step in analysis of the requirements which a new refinery or expansion must comply with will be to examine either the revised and approved implementation plan or the existing and the proposed implementation plan and determine which of its provisions may be applicable.

The Clean Air Act and the state implementation plans contain numerous other elements which are enormously important but not sufficiently pertinent to new refineries or expansions to be described in this report.

TABLE 41 STATUS OF STATE IMPLEMENTATION PLAN PROGRAM
JANUARY 28, 1980

State	SIP Submitted to EPA	SIP Complete Acceptance by EPA
Alabama	X	
Alaska	X	
Arizona		
Arkansas	X	
California		
Colorado	X	
Connecticut	X	
Delaware	X	
District of Columbia	X	
Florida	X	
Georgia	X	
Hawaii	X	
Idaho		
Illinois	X	
Indiana		
Iowa	X	
Kansas		
Kentucky	X	
Louisiana	X	
Maine	X	
Maryland	X	
Massachusetts	X	
Michigan	X	
Minnesota		
Mississippi	X	X
Missouri		
Montana	X	

TABLE 4i STATUS OF STATE IMPLEMENTATION PLAN PROGRAM
JANUARY 28, 1980 (Continued)

State	SIP Submitted to EPA	SIP Complete Acceptance by EPA
Nebraska	X	
Nevada	X	
New Hampshire		
New Jersey	X	
New Mexico	X	
New York	X	
North Carolina	X	
North Dakota	X	
Ohio		
Oklahoma	X	
Oregon	X	
Pennsylvania		
Rhode Island	X	
South Carolina	X	
South Dakota	X	
Tennessee		
Texas	X	
Utah	X	
Vermont	X	
Virginia	X	
Washington	X	
West Virginia	X	
Wisconsin	X	
Wyoming	X	X

These include, for example, the auto standards and the transportation control plans. Special standards, known as national emission standards for hazardous air pollutants (NESHAPS), apply to all plants, new or old, which emit hazardous pollutants such as asbestos, beryllium, mercury or vinyl chloride. Arsenic and benzene are currently under consideration for regulation under NESHAPS. More details about NESHAPS can be found in 40 CFR 61. The first couple pages of 40 CFR 61 can be found in Appendix D-6.

4.2.5 New Source Performance Standards

One component of the program which bears specifically on new plants, however, is the directive to EPA to set New Source Performance Standards (NSPS) for individual industrial categories in which petroleum refineries are considered, requiring new plants to utilize the best system of emission reduction which the Administrator determines has been adequately demonstrated.

EPA has gradually issued a series of these standards, which now cover a number of basic industrial categories. The 1977 Amendments directed EPA to accelerate this program, so that within the next few years standards should be issued for most other significant industrial categories. Existing industrial categories which have standards and industrial categories for which NSPS will be developed are shown in Table 42 and 43 respectively.

There are two New Source Performance Standards which can affect a new refinery or expansion. These are NSPS for petroleum refineries (40 CFR 60, Subpart J) and the NSPS for storage vessels for petroleum liquids (40 CFR 60, Subpart K).

The New Source Performance Standards for petroleum refineries are applicable to fluid catalytic cracking (FCC) unit catalyst regenerators, flue gas combustion devices, and all Claus sulfur recovery plants except Claus plants of 20 long tons per day or less associated with a small petroleum refinery. These standards regulate the following pollutants:

TABLE 42 INDUSTRIES WHICH HAVE DEVELOPED NEW SOURCE PERFORMANCE STANDARDS (40 CFR 60)

Subpart	Industrial Category
D	Fuel fired steam generators for which construction is commenced after August 17, 1971
Da	Electric utility steam generating units for which construction is commenced after September 18, 1978
E	Incinerators
F	Portland cement plants
G	Nitric acid plants
H	Sulfuric acid plants
I	Asphalt Concrete Plants
J	Petroleum refineries
K	Storage vessels for petroleum liquids
L	Secondary lead smelters
M	Secondary brass and bronze ingot production plants
N	Iron and steel plants
O	Sewage treatment plants
P	Primary copper smelters
Q	Primary zinc smelters
R	Primary lead smelters
S	Primary aluminum reduction plants
T	Phosphate fertilizer industry: wet process phosphoric acid plants
U	Phosphate fertilizer industry: superphosphoric acid plants

TABLE 42 INDUSTRIES WHICH HAVE DEVELOPED NEW SOURCE PERFORMANCE STANDARDS (40 CFR 60) Continued

Subpart	Industrial Category
V	Phosphate fertilizer industry: Diammonium phosphate plants
W	Phosphate fertilizer industry: triple superphosphate plants
X	Phosphate fertilizer industry: granular triple superphosphate storage facilities
Y	Coal preparation plants
Z	Alloy production facilities
AA	Steel plants: electric arc furnaces
BB	Kraft pulp mills
DD	Grain elevators
GG	Stationary gas turbines
HH	Lime manufacturing plants

TABLE 43 NEW SOURCE PERFORMANCE STANDARDS TO BE DEVELOPED[4]
(40 CFR 60.16)

Priority Number[1]	Source Categories
1	Synthetic Organic Chemical Manufacturing
	(a) Unit processes
	(b) Storage and handling equipment
	(c) Fugitive emission sources
	(d) Secondary sources
2	Industrial Surface Coating: Cans
3	Petroleum Refineries: Fugitive Sources
4	Industrial Surface Coating: Paper
5	Dry Cleaning
	(a) Perchloroethylene
	(b) Petroleum solvent
6	Graphic Arts
7	Polymers and Resins: Acrylic Resins
8	Mineral Wool
9	Stationary Internal Combustion Engines
10	Industrial Surface Coating: Fabric
11	Fossil-Fuel-Fired Steam Generators: Industrial Boilers
12	Incineration; Non-Municipal
13	Non-Metallic Mineral Processing
14	Metallic Mineral Processing
15	Secondary Copper
16	Phosphate Rock Preparation
17	Foundries: Steel and Gray Iron
18	Polymers and Resins: Polyethylene
19	Charcoal Production
20	Synthetic Rubber
	(a) Tire manufacture
	(b) SBR production
21	Vegetable Oil
22	Industrial Surface Coating: Metal Coil
23	Petroleum Transportation and Marketing
24	By-Product Coke Ovens
25	Synthetic Fibers
26	Plywood Manufacture
27	Industrial Surface Coating: Automobiles
28	Industrial Surface Coating: Large Appliances
29	Crude Oil and Natural Gas Production
30	Secondary Aluminum
31	Potash
32	Sintering: Clay and Fly Ash
33	Glass
34	Gypsum
35	Sodium Carbonate
36	Secondary Zinc

TABLE 43 NEW SOURCE PERFORMANCE STANDARDS TO BE DEVELOPED (40 CFR 60.16) Continued

Priority Number[1]	Source Categories
37	Polymers and Resins: Phenolic
38	Polymers and Resins: Urea--Melamine
39	Ammonia
40	Polymers and Resins: Polystyrene
41	Polymers and Resins: ABS-SAN Resins
42	Fiberglass
43	Polymers and Resins: Polypropylene
44	Textile Processing
45	Asphalt Roofing Plants
46	Brick and Related Clay Products
47	Ceramic Clay Manufacturing
48	Ammonium Nitrate Fertilizer
49	Castable Refractories
50	Borax and Boric Acid
51	Polymers and Resins: Polyester Resins
52	Ammonium Sulfate
53	Starch
54	Perlite
55	Phosphoric Acid: Thermal Process
56	Uranium Refining
57	Animal Feed Defluorination
58	Urea (for fertilizer and polymers)
59	Detergent

Other Source Categories

Lead acid battery manufacture[2]
Organic solvent cleaning[2]
Industrial surface coating: metal furniture[2]
Stationary gas turbines[3]

---

1 Low numbers have highest priority; e.g., No. 1 is high priority, No. 59 is low priority.

2 Minor source category, but included on list since an NSPS is being developed for that source category.

3 Not prioritized, since an NSPS for this major source category has already been proposed.

4 This list was issued under §311 of the Clean Air Act by EPA on November 9, 1979 (40 CFR 60.16).

- particulate matter from FCC unit catalyst regenerator or FCC unit regenerator incinerator-waste heat boilers (lb/1000 lb of coke burn-off).

- carbon monoxide from FCC unit catalyst regenerators (percent).

- sulfur dioxide from fuel gas combustion devices (lb/dscf) and Claus sulfur recovery plants (percent)

- opacity from the FCC unit catalyst regenerator or from the FCC unit regenerator incinerator-waste heat boiler (percent).

Continuous monitoring is required for opacity, and sulfur dioxide. Continuous monitoring will be required for carbon monoxide and hydrogen sulfide as soon as the instrument specification are promulgated by the EPA. Any periods where the emission of pollutant(s) is in excess of the standards, a report shall be filled with the EPA. The complete standards and the amount of each pollutant which can be emitted, details on monitoring, and reports of excess emissions can be found in 40 CFR 60, SUBPART J, which is in Appendix D-7. A summary of these standards are shown in Table 44.

These standards are currently being reviewed by the EPA and major changes in the standards for sulfur dioxide emissions especially around the FCC unit regenerator. The EPA has made only recommendations and these recommendations are as follows:

Particulate Matter

- Do not change the present standard of 1.0 lb/1,000 lb coke burn-off and 30 percent opacity.

- Reevaluate the Reference Method 5 for particulate matter.

- Require that opacity be measured when mass loading tests are made.

Carbon Monoxide

- Collect data to ascertain the level of carbon monoxide emissions from high temperature (in situ) regenerators with and without the use of CO oxidation catalysts and additives.

- Reevaluate the carbon monoxide standard in light of the findings from the above research.

TABLE 44 NEW SOURCE PERFORMANCE STANDARDS FOR PETROLEUM REFINERIES (40 CFR 60, SUBPART J)

AFFECTED FACILITY	POLLUTANT	EMISSION LEVEL	MONITORING REQUIREMENT[2]
Fluid catalytic cracking unit catalyst regenerator	Particulate[1]	1.0 lb/1000 lb of coke burn-off	No requirement
	Opacity	30% (6 min exemption)	Continuous
	CO	0.05%	Continuous
Fuel gas combustion devices	SO_2	0.10 gr/dscf	Continuous
	H_2S	230 mg/dscm	Continuous
Claus Sulfur recovery plants	SO_2	0.025% (at 0% oxygen)	Continuous
	Reduced sulfur compounds plus	0.030% (at 0% oxygen)	Continuous
	H_2S	0.0010% (at 0% oxygen)	Continuous

1 Where the gases are discharged through an incinerator or waste heat boiler in which an auxiliary fuel, liquid or solid fossil, is used, particulate matter in excess of 1.0 lb/1000 lb of coke burn-off may be emitted at a rate of 0.1 lb/million BTU of heat input or less.
2 Continuous monitors are used to determine excess emissions only.

Sulfur Dioxide

- Change the definition of a fuel gas combustion device to include the regenerator incinerator-waste heat boiler by deleting the exemption.

- Develop a continuous monitoring method for hydrogen sulfide.

- Reevaluate the present standard in light of the effect of an increased sulfur content of feedstock on the concentration of hydrogen sulfide in fuel gas and of current compliance test data on achievable levels of hydrogen sulfide in fuel gas.

- Investigate FCC unit regenerator sulfur oxide control technology, including cost, performance, applicability, effect of feed stock, etc. Subject to the findings of such an investigation, develop a standard for sulfur dioxide emissions from FCC unit regenerators.

Hydrocarbons

- Evaluate the effect of: conventional regeneration, CO boilers, high temperature regeneration, and regeneration with CO combustion catalysts and additives on the emission of hydrocarbons from FCC unit regenerators.

- Assess the need for the regulation of hydrocarbon emissions from FCC unit regenerators based on results from the above research.

A complete copy of the review can be obtained from the EPA by ordering EPA-450/3-79-008 while a copy of the Table of Contents and the executive summary can be found in the Appendix D-8.

The New Source Performance Standard for Storage Vessels for Petroleum Liquids are applicable to storage vessels which have a storage capacity of greater than 40,000 gallons. This subpart does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility. This standard regulates the hydrocarbon emissions from these tanks by the use of floating roofs and/or a vapor recovery system, and is based upon the true vapor pressure of the fluid being stored. The standards are as follows:

- If the true vapor pressure of the petroleum liquid, as stored, is equal to or greater than 78 mm Hg (1.5 psia) but not greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a floating roof, a vapor recovery system, or their equivalent.

- If the true vapor pressure of the petroleum liquid as stored is greater than 570 mm Hg (11.1 psia), the storage vessel shall be equipped with a vapor recovery system or its equivalent.

Details of this standard can be found in 40 CFR 60, Subpart K, located in the Appendix D-9.

The standards discussed above are the federal standards. Each state in their SIP program have standards for Petroleum Refineries and Storage of Petroleum Liquids which cannot exceed, but may be more stringent than, the federal standards. Also, local standards within the state can be more stringent than the state or federal standards. It is very important for a company planning either a new refinery or an expansion and for the local government and citizens of the area being considered to fully understand and follow these standards.

These basic requirements established under the state implementation plans and any applicable new source performance standard alone should not affect the decision of whether or not to construct a new refinery or expand an existing refinery at a particular site and state. However, the Clean Air Act created two additional complex regulatory frameworks which must be considered in reference to any new refinery or expansion and they do affect the decision of the site and state. These are the requirements to prevent significant deterioration (PSD) of air quality in areas of the country currently cleaner than the air quality standards and the non-attainment requirements which apply in areas continuing to violate the air quality standards. The intricacies of these requirements will require detailed explanation.

4.2.6 Prevention of Significant Deterioration

Of all the federal laws placing environmental controls on a new refinery or an expansion, perhaps the most complex and also most restrictive are the limits imposed by the Clean Air Act to prevent significant deterioration of air quality. These limits, commonly referred to as PSD, apply in areas of the country which are already cleaner than required to meet the ambient air quality standards (Part C of the Clean Air Act). It should be noted that the PSD framework is being contested in court and the final outcome will effect major sections. This is discussed in Section 4.2.10.

- Background

This regulatory framework evolved out of judicial and administrative action under the 1970 Clean Air Act, and subsequently was given a full statutory foundation by the 1977 Clean Air Act Amendments. It is therefore particularly useful to examine that background and the basic concepts as they evolved. As enacted in 1970, the Clean Air Act contained no provisions dealing explicitly with protection of air quality in clean air regions. The entire structure of regulatory controls established through the state implementation plans focused on reducing existing levels of pollution in areas where the air quality standards were being violated. The Act did require EPA to promulgate new source performance standards to require new plants wherever located to install the best systems of emission reduction found by the Administrator to have been adequately demonstrated. Some people feared, however, that the tight controls in the implementation plans would force new industrial growth into areas of the country where little or no previous industrialization had occurred, with a risk of downgrading the existing high air quality of such areas. This fear applied particularly to the anticipated contruction of huge coal-fired powerplants in portions of the Southwest historically known for their pristine air permitting visibility for distances as high as 80 miles.

The idea of establishing some controls to prevent the deterioration of good air quality had been considered in the legislative history of the 1970 Act, and an early draft of EPA guidelines under the Act would have encouraged states to develop such controls. The regulations finally promulgated by EPA to specify required elements in the state implementation plans, however, made no mention of such controls. That omission was challenged in a lawsuit brought by the Sierra Club. The suit ultimately resulted in a decision, Sierra Club vs. Train, by the U.S. Supreme Court, which by a four-to-four tie vote left in effect a lower court decision in favor of the Sierra Club. This required EPA to develop some form of regulatory program to prevent significant deterioration.

Having no guidance at all from either Congress or the courts as to the nature of the controls it was required to establish, EPA was obliged to come up with the program on its own. The Agency's approach reflected a judgment that the amount of deterioration of air quality which should be permitted as a consequence of industrial development should retain some flexibility to respond to judgments made through the local political process on the extent of industrial growth desired in a given region. Accordingly, EPA established an area classification scheme to be applied in all clean air regions. The basic idea was that a moderate amount of industrial development should be routinely permitted in all areas but that industrialization should not be allowed to degrade air quality to the point that it barely complied with air quality standards, in the absence of the conscious public decision in favor of such growth. In addition, an opportunity should be provided for states to designate certain areas where pristine air quality was especially valued and any growth generating significant emissions of pollutants should be tightly curtailed. Thus, the system for classifying all areas as Class I, Class II, or Class III, was developed.

The Class I category was to include the pristine areas subject to tightest control. Class II covered areas of moderate growth. Class III was for areas of major industrialization. Under the EPA regulations, promulgated in December 1974, all areas were initially classified as Class II. States were authorized to reclassify specified areas to be either Class I or Class III.

The EPA regulations also established another concept known as the increment. This is the numerical definition of the amount of additional pollution which may be allowed through the combined effects of all new growth in a particular locality.

The increment system may be illustrated by the annual average limitations established for particulate matter. For Class II areas the maximum increase in particulate concentration was initially set by EPA at 10 micrograms per cubic meter, whereas in Class I areas the increase allowed was only half as great, namely 4 micrograms per cubic meter. For reference, the annual ambient air quality standards for particulate matter had been established at 75 micrograms per cubic meter as a primary standard and 60 micrograms per cubic meter as a secondary standard (See Table 39 and 40 in Section 4.2.3).

This meant that if the level of existing pollution (the "baseline") was at an annual average of 30 micrograms per cubic meter, new sources would be allowed to increase that level to 40 micrograms per cubic meter in a Class II area, but only to a level of 35 micrograms per cubic meter if the area was reclassified as Class I. If the area were changed to Class III, unlimited growth would be permitted so long as it did not threaten to push pollution levels above the air quality standard of 60 micrograms per cubic meter.

Limits were set for short-term concentrations as well as the long-term annual standards. Moreover, the PSD requirements applied to sulfur dioxide in addition to particulate matter. Thus several separate analyses were called for to verify that none of the PSD increments might be violated by a major new plant.

Since the PSD scheme does contemplate that certain limitations would be placed on the amount of growth permitted in any given area, an implicit question was whether a system would be devised to select which industrial projects would be permitted to use up the available increment or whether that would simply be resolved on a first-come, first-served basis. EPA did not undertake to resolve that question. Its initial analysis indicated that the numerical limits selected would be sufficient to allow substantial industrial development in any Class II area. Hence the program would not be apt to pinch new projects, at least in its early years.

EPA did impose one major additional requirement to assure that the increments would not be used up hastily. It specified that each major new plant must install the best available control technology (BACT) to limit its emissions. This reinforced the same policy underlying the new source performance standards, and indeed EPA declared that where new source performance standards had been promulgated they would control determinations of BACT. Where such standards had not been promulgated, an ad hoc determination was called for in each case.

To implement these controls, EPA imposed a requirement that each new source undergo a preconstruction review and as part of this review, public notice should be given and an opportunity provided for a public hearing on any disputed questions of fact. The regulation prohibits a company from commencing construction on a new source until this review has been completed.

A fundamental feature of the PSD regulation adopted by EPA was the limited nature of the program. It excluded the automobile pollutants (hydrocarbons, photochemical oxidants, carbon monoxide, and nitrogen oxide) from the program altogether. It also excluded numerous miscellaneous activities which might cause pollution, as well as the construction of new small sources. Also, the new controls applied only to large new plants within 19 specific industrial categories, such as powerplants, steel mills, refineries, etc.

- 1977 Amendments to the Clean Air Act

The current significance of the PSD program established by EPA in 1974 is when Congress in 1977 provided the first statutory foundation for PSD and adopted it into the basic concepts of the EPA program. Congress made many changes in critical elements, however, and in virtually every case the effect of those changes was to broaden the program and tighten its requirements. Congress statutorily placed many areas in the pristine air Class I category, and made it quite difficult for states to redesignate areas to be Class III. It also tightened some of the increments. Congress expanded the number of industrial plants subject to the PSD review and tightened the requirements of BACT. Congress also directed EPA to extend the PSD framework to other pollutants in addition to sulfur oxides and particulates, required more monitoring to be done, and added other new data requirements. Finally, they expanded the procedures for government and public review of PSD applications. The combined effect of all these changes convert the PSD review into a complex regulatory process confronting a refinery project.

Congress failed to prescribe the time schedule by which these new requirements would go into effect. This uncertainty spawned litigation which resulted in a brief delay in March 1978 in EPA's approval of a number of large projects. Under the rules finally set by EPA on June 19, 1978, the principal new requirements were made effective for all new refineries or expansions unless they had obtained all air quality permits and approvals before March 1, 1978, and also commenced construction not later than March 19, 1979.

Area Classification and Increments

In 1977, Congress continued in effect the three-class system established by EPA, but with several changes. One change was to direct by statute that certain areas are permanently designated Class I. These are: (1) international parks, (2) national wilderness areas and memorial parks exceeding 5,000 acres, and (3) national parks exceeding 6,000 acres. Although the nature of these areas is such that industrial projects would not be located within them, their Class I status will affect projects in neighboring areas if the winds might carry their emissions into these areas. For many projects, particularly in the West, this may be a substantial constraint.

The statute provides that, except for areas specifically placed in Class I, all other areas in the country subject to PSD shall be initially designated Class II. States are then authorized to redesignate areas either as Class I or as Class III. Before doing so, a state must hold a public hearing in the affected area and prior to the hearing must prepare a detailed analysis, similar in nature to an environmental impact statement, describing the effects of the proposed redesignation.

If the proposal is to redesignate an area as Class III, additional requirements apply. The redesignation must be specifically approved by the governor of the state, after consultation with the state legislature, and general purpose units of local government representing a majority of the residents of the area must enact legislation approving the change. In view of these requirements, it is likely that redesignations to Class III will be few and far between. The statute also states that certain areas, including wildlife refuges and scenic rivers, may never be designated Class III.

The 1977 Amendments made various changes in the numerical limitations comprising the increments of pollution increase allowed in Class II and Class III areas. The numbers of Class II were generally loosened slightly, except for the short-term sulfur dioxide limitations which were tightened. For Class III, the statute established increment limitations, instead of allowing unlimited growth subject only to compliance with the air quality standards themselves. The increment limitations and the national primary ambient air quality standards are shown in Table 45.

The 1977 amendments require EPA to conduct a study on the following pollutants:

- hydrocarbons
- carbon monoxide
- photochemicals
- nitrogen oxides.

The EPA shall promulgate regulations by August of 1979 to prevent the significant deterioration of air quality by the emission of these pollutants. Such regulations would become effective one year later. EPA shall also provide an increment for each as done for sulfur dioxide and particulate.

TABLE 45 PSD AIR QUALITY INCREMENTS (DECEMBER 1979)

CLASS I AREA

Pollutant	Maximum Allowable Increase ($\mu g/m^3$)[3]	Primary Ambient Air Quality Standard[1]
Particulate matter:		
Annual geometric mean	5	75
Twenty-four-hour maximum	10	260
Sulfur dioxide:		
Annual arithmetic mean	2	80
Twenty-four-hour maximum	5	365
Three-hour maximum	25	1300[1]

CLASS II AREA

Pollutant	Maximum Allowable Increase ($\mu g/m^3$)	Primary Ambient Air Quality Standard[1]
Particulate matter:		
Annual geometric mean	19	75
Twenty-four-hour maximum	37	260
Sulfur dioxide:		
Annual Arithmetic mean	20	80
Twenty-four-hour maximum	91	365
Three-hour maximum	512	1300[2]

CLASS III AREA

Pollutant	Maximum Allowable Increase ($\mu g/m^3$)	Primary Ambient Air Quality Standard[1]
Particulate matter:		
Annual geometric mean	37	75
Twenty-four-hour maximum	75	260
Sulfur dioxide:		
Annual arithmetic mean	40	80
Twenty-four-hour maximum	182	365
Three-hour maximum	700	1300[1]

[1] These figures are the National Ambient Air Quality Standards.
[2] The three-hour maximum figure for SO_2 represents the secondary standard rather than a primary standard.
[3] Micro-gram per cubic meter.

As of December of 1979, the EPA has not promulgated any regulations pertaining to the above pollutants. A new refinery or expansion should follow the existing PSD air quality increments for sulfur dioxide and particulates but should follow any development of any future regulation on the pollutants cited above.

- Sources Subject to PSD

A critical threshold question for any company planning a new project is whether it requires preconstruction approval under PSD. The 1977 Amendments increased from 19 to 28 the number of industrial categories specifically identified in which any new plant with potential emissions exceeding 100 tons per year would be covered. In addition, a new plant in any other category is also covered if its potential emissions of any pollutant would exceed 250 tons per year.

In determining whether an area is subject to PSD requirements, each individual pollutants must be considered. Since most areas of the country are in compliance with the sulfur dioxide standards (with the notable exception of major industrialized regions), most areas likewise are subject to PSD. If an area falls under PSD on the basis of its levels of sulfur dioxides, a source within that area will become subject to the PSD requirements if its emissions of any pollutant regulated by the Clean Air Act exceed the size cut-off. As of December 1978 these pollutants include particulates, sulfur dioxides, photochemical oxidants, carbon monoxide, nitrogen dioxide, hydrocarbons, lead, beryllium, mercury, vinyl chloride, asbestos, flouride and sulfuric acid mist. A source may also become subject to the PSD requirements even though located outside the PSD areas, if its emissions, for example particulate, would impact a PSD area.

Modifications of existing plants are subject to the PSD requirements in the same way as are new plants, if the modification would increase potential emissions by amounts exceeding the size cutoff, with a special exemption from the increment analysis for Class II areas to facilities in "existence" on August 7, 1977, whose allowable emissions with controls will be less than 50 tons per year. EPA regulations provide the exemption from BACT and impact analysis if the modification by which emissions are increased is accompanied by other changes within an overall plant with the result of a zero net increase in total emissions.

The kicker in the Amendments was the inclusion of the word "potential" in the description of sources subject to PSD. That wording apparently was intended by Congress and has been interpreted by EPA as requiring that the size of plants must be tested by determining the quantity of emissions they would generate if operated at full capacity but without benefit of the pollution control systems which in fact would be required. This multiplies the number of plants exceeding the 100 and 250 ton-per-year levels, bringing in many small plants whose actual emissions would only be a fraction of the cutoff number after pollution controls have been applied.

It should be noted that this is one area which is being contested in the Alabama vs. EPA case. The results of this case may define the limits (100 tons or 250 tons) after controls have been applied. This is discussed in Section 4.2.10.

In an effort to meet this situation, the EPA regulations of June 19, 1978, established a two-tier system, in which the larger plants are made subject to the full PSD review prescribed by the statute, whereas the more numerous smaller plants are exempted from full PSD review. Those smaller plants subject to the full review would include any new source (or major modification) which, after applying its pollution control system, would have allowable emissions exceeding 50 tons per year, or 1,000 pounds per day, or 100 pounds per hour. That full review includes (1) a case-by-case determination of the controls required by BACT, (2) an ambient impact analysis to determine whether the source might violate applicable increments or air quality standards, (3) an assessment of effects on visibility, soils, and vegetation, (4) submission of monitoring data, and (5) full public review.

The EPA regulations exempt the smaller sources from the major elements of the PSD review, and in particular relieve those sources of the need to comply with BACT (though they must still comply with any applicable new source performance standards, as well as requirements under the state implementation plans) and the need to conduct an ambient impact analysis or submit data supporting an ambient air quality analysis. Nonetheless, the small sources are not exempted from the program altogether. They remain subject to the statutory requirement to apply for and obtain a preconstruction approval, including procedures for public review, and they may be required to submit data supporting their application at the request of the Agency. In addition, if the emissions from a small source would affect a Class I area or an area where the applicable increment is not being violated, the full PSD requirements for ambient impact analysis will apply. A brief summary of what plants are subject to PSD is shown on Table 46.

- Best Available Control Technology (BACT)

The critical feature of BACT is that it must be determined for each plant on a case-by-case basis. The statute specifies that "energy, environmental, and economic impacts and other costs" must be taken into account. It also states that in no case can BACT be more lenient than any applicable new source performance standard, implying that wherever possible it will be more stringent. Although the statute provides that BACT shall be required "for each pollutant subject to regulation under this Act," the EPA regulations state that BACT need be met only for those pollutants which the particular source has the potential to emit in quantities exceeding the size cutoff levels.

- PSD Permit

As stated earlier, for a new source to start construction, a permit would be required. For the source to be located in a PSD area, the following criteria must be met:

- emissions from the source must not exceed the PSD increment for the area,

TABLE 46 WHAT PLANTS ARE SUBJECT TO PSD (DECEMBER 1979)

Application of PSD requirements depends on two factors: (1) location of plant, and (2) nature of plant and quantity of potential emissions.

(1) Location -- PSD rules apply if at location of plant no violations exist of air quality standards for any NAAQS pollutant, based on latest air quality data; PSD also applies if emissions from new plant will be transported in the atmosphere and adversely impact any such area.

(2) Potential emissions -- PSD applies to emissions of any regulated pollutant exceed 100 tons per year and plant falls within one of the following 28 industrial categories:

Fossil Fuel-Fired Steam Electric Plants of More than 250 Million Btu/Hr Heat Input	Coke Oven Batteries
Coal Cleaning Plants (Thermal Dryers)	Sulfur Recovery Plants
Kraft Pulp Mills	Carbon Black Plants (Furnace Process)
Portland Cement Plants	Primary Lead Smelters
Primary Zinc Smelters	Fuel Conversion Plants
Iron and Steel Mill Plants	Sintering Plants
Primary Aluminum Ore Reduction Plants	Secondary Metal Production Facilities
Primary Copper Smelters	Chemical Process Plants
Municipal Incinerators Capable of Charging More than 250 Tons Refuse/Day	Fossil-Fuel Boilers of More Than 250 Million Btu/Hr Heat Input
Hydrofluoric, Sulfuric, Nitric Acid Plants	Petroleum Storage and Transfer Fac. w/Capacity Exceeding 300,000 Barre
PETROLEUM REFINERIES	Taconite Ore Processing Facilities
Lime Plants	Glass Fiber Processing Plants
Phosphate Rock Processing Plants	Charcoal Production Facilities

For all other industrial categories, new plants will be subject to PSD if potential emissions exceed 250 tons per year.

Note: "Potential emissions" refer to raw emission levels, measured before application of control devices such as dust collectors, precipitators, scrubbers, etc. This includes fugitive emissions.

- the source must conduct air quality monitoring to determine if any standard or increment will be violated,
- the source must include in its air quality analysis emissions from any growth associated with the facility,
- the source must be designed according to State Standards of Performance for new facilities,
- the source must use "Best Available Control Technology" in controlling its emissions,
- the source must determine if there will be any adverse impact on any area classified as "pristine," and
- must provide opportunity for a public hearing prior to issuing of the construction permit.

The time required for approval of the permit under the PSD program is next to impossible to predict. It will vary greatly depending on the complexity and controversiality of the project, and this will be discussed in the permit section of this report.

The PSD program discussed above is currently being contested in court (Alabama Power Company vs. EPA). The final decision of this case will invalidate major sections of the PSD program. This case is discussed in Section 4.2.10 and a copy of the decision can be found in Appendix D-2.

4.2.7 Nonattainment

The country can be divided into "clean" air areas and "dirty" air areas. PSD sets the requirements to be met by new refinery projects in clean areas. A parallel set of requirements must be met by new refinery projects in the dirty areas. These are established by the "nonattainment" provisions of the Clean Air Act, so labeled because these areas have failed to "attain" compliance with the ambient air quality standards (Part D of the Clean Air Act). Where they apply, the nonattainment provisions are apt to be more restrictive and complex than the requirements under PSD.

• Background

In developing state implementation plans to achieve compliance with the ambient air quality standards, state agencies concentrated on cleaning up pollution from existing sources. The EPA regulation did also require, however, that each state implementation plan set forth enforceable procedure by which a state could determine whether new sources would interfere with the attainment or maintenance of a national air quality standard and could prevent the construction of new sources where it would cause such adverse effects on the ambient air. In the early years following adoption of these state implementation plans in 1972, little attention focused on the preconstruction review of new sources for this purpose, although commonly state agencies did review new sources to assure compliance with other requirements in the implementation plans and any applicable new source performance standards. It was generally assumed that the air quality standards would be achieved and that new sources would not be expected to cause significant problems. Moreover, the efforts of regulatory agencies were consumed in establishing controls on existing sources.

By 1975 a different picture began to appear. With the passage of the initial deadline for achieving the air quality standards, it gradually became clear that continuing violations would be widespread. The accumulation of air quality data converted a theoretical concern into a practical concern. This concern is whether or not the Clean Air Act intended to stop new industrial construction throughout substantial portions of the country.

After long debate, EPA attempted to reconcile the conflicting national concerns for clean air and economic growth. It issued its Offsets Policy as an Interpretative Ruling in the Federal Register on December 21, 1976. The ruling stated that new plants could be constructed in nonattainment areas, but only if stringent conditions were met. These required that emissions must be controlled to the greatest degree possible and that more than equivalent offsetting emission reductions must be obtained from other sources to assure progress toward the achievement of clean air.

More specifically, the ruling established the following criteria for approval of a new source in a nonattainment area: (1) the new source must be equipped with pollution controls to assure the lowest achievement emission rate (LAER), which in no case could be less stringent than any applicable new source performance standard; (2) all existing sources owned by an applicant in the same region must be in compliance with applicable implementation plan requirements or under an approved schedule or an enforcement order to achieve such compliance; (3) the applicant must demonstrate sufficient "offsets" -- reductions in emissions from other existing sources-- to more than make up for the emissions to be generated by the new source (after application of LAER); and (4) the emission offsets must provide a positive net air quality benefit in the affected region.

The formulation of this EPA policy occurred simultaneously with Congressional review of the Clean Air Act, and the nonattainment problem became one of the chief controversies addressed by Congress in the 1977 Amendments. As in the case of PSD, Congress wrote into the law provisions patterned closely after the approach adopted by EPA. In this case, Congress took the unusual step of providing by statute that EPA's prior Interpretative Ruling should remain in effect until July 1, 1979, unless modified by another EPA rule. Following that date revised state implementation plans are intended to provide the basic framework for review of new sources in nonattainment areas. In general the same approach will continue to apply, but subject to a number of specific modifications, which tightens the restrictions on constructions of new plants. The most important of these provisions links the approval of individual new sources to the completion of a process of revising the entire state implementation plans wherever necessary to eliminate violations of the air quality standards by July 1, 1979. This provision will prohibit construction of new plants in a number of nonattainment areas unless the SIP revision process moves forward in accordance with tight time schedules.

On January 16, 1979, EPA issued new regulations revising the original Interpretative Ruling. These revisions to the Interpretative Ruling incorporate a number of significant changes prompted by the 1977 Amendments but preserve the basic framework of the earlier ruling. A copy of these revisions by the January 16, 1979, ruling can be found in Appendix D-10.

Offsets

The premise underlying the offsets policy is that even where severe abatement measures have already been required, untapped opportunities may exist for further emission reductions. Thus if additional new commitments are made to control pollution, the net effect of approval of a new source will not increase pollution and therefore will not aggravate a violation of the air quality standards. This rationale explains one fundamental characteristic of offsets that they must represent emission reductions that otherwise would not be required.

The offset rules are applied on a pollutant-specific basis, with offsets required only with respect to the pollutant for which the standards violation exists. If the locality of the new plant is a nonattainment area for two or more pollutants, then offsets would be required for each.

Considerable flexibility exists as to the type of offsets which may be acceptable. The first possibility whenever the new source represents an expansion of an existing refinery is for the owner to install tighter controls on existing operations. This might include use of new and innovative technology or controls that would not normally be required even in the revision of SIPs to resolve nonattainment problems.

Where such offsets are unavailable, including by definition any case where an entirely new refinery is proposed, the applicant must explore other alternatives. The applicant may be able to deal with another large industrial plant in the area to apply extra pollution control measures, with a sum of money changing hands in the process. This method would be very expensive and the legal aspects (ownership, maintenance, etc.) could be very complex. In some cases, an applicant may be able to purchase an existing facility in order to clean it up or close it down, particulately an old, obsolete plant with large pollutant emission. As this regulatory program develops, a market for pollution rights may develop in severe nonattainment areas.

The search for offsets occasionally may include government officials. Where a large industrial project promising jobs to a local economy hangs in the balance, public support and government assistance may be rallied. Regulatory officials might clear the path for a new project by putting pressure on existing sources to meet more stringent pollution control requirements. The government might even produce the offsets itself. For example, in a case involving a proposed new Volkswagen plant in Pennsylvania, the state modified its plans for resurfacing roads (switching to a material that would generate fewer hydrocarbon emissions) to provide the needed offsets. Other actions a local government could take might include paving roads to reduce particulate emissions. Through such mechanisms the element of local political support for a project can be very critical.

Whatever the offsets may be, they must be "nailed down" as legally binding components of the state's air pollution control program. This includes a requirement that the commitments be enforceable by EPA as well as by the state. In many cases the method to give this legal authority to the offsets will be an actual revision of the state's implementation plan, although alternative methods can be used under certain conditions.

The quantity of offsets must match emissions from the new source or the expansion on a "more than one-to-one" basis. The exact amount of offsets over new emissions required is determined by the reviewing agency of the project.

A factor that might bear upon the quantity of offsets required relates to the location of the offsets in reference to the proposed new plant. Under EPA's Interpretative Ruling (original and revised) a specific condition for approval of a new source requires the demonstration of a net air quality benefit to result from the new project plus offsets. This requirement can be met where the offsets are obtained by reductions at the same plant as the new source, since any set of reductions more than offsetting the added emissions would in fact produce a net air quality benefit. Likewise, in dealing with pollutants of a regional air nature such as photochemical oxidants, reductions of pollutants in the same general area would produce an air quality benefit.

With pollutants such as particulates, however, reductions at one spot within a nonattainment area would not necessarily compensate for an increase of emissions some distance away. The net air quality benefit rule has been generally understood to require that there be no serious detriment anywhere due to the new source. This therefore may present an additional requirement.

- Banking of Offsets

In its original Interpretative Ruling, EPA explicitly rejected the concept of banking offsets. It declared that no offset credit could be claimed for any reduction or elimination of emissions occurring more than one year before application for approval of a new source, though it did allow the possibility of applying a large offset against subsequent stages of a multi-phase expansion program. One impact of this rule is that it discourages any reduction in emissions beyond what is specifically required. An incentive exists for a company to continue maximum permitted emissions for future use as offsets. This incentive may also encourage the continued operation of obsolete facilities beyond their normal useful life for future offsets.

In the January 16, 1979, revision of the Interpretative Ruling EPA modified the prohibition on banking of offsets by providing that states, as part of a revised SIP meeting the requirements of the Act, may allow banking subject to certain conditions. Banked emissions must be identified and accounted for in the state's SIP control strategy. States may allow credit for source shutdowns, provided they have occurred after July 7, 1977. A company planning to construct a new refinery or expand an existing facility should carefully review the applicable SIP with regards to the banking of offsets.

- Sources Covered

As with PSD, the nonattainment requirements do not apply to every new source but only to those defined as a "major" new source (or major modification). Under the revised Interpretative Ruling the test is whether potential emissions from the new facility will exceed 100 tons per year of any one of the following pollutants: particulate matter, sulfur oxides, nitrogen oxides, volatile organic compounds, or carbon monoxide. By contrast, the PSD program can be triggered by any pollutant regulated under the Act if emissions exceed the 100-ton test for plants within a list of 28 industrial categories or the 250-ton cutoff for all other sources.

In the 1977 Amendments Congress made a fundamental change, vastly expanding the coverage of the program by applying the numerical cutoff to "potential" emissions rather than allowable emissions. In implementing this change EPA has sought to narrow its impact by establishing a two-tier system similar to that established under the PSD program. Although all major new refineries or expansions must be reviewed to assure compliance with provisions of the state implementation plan and any new source performance standards, the full nonattainment requirements apply only to those facilities with actual emissions exceeding 50 tons per year, 1000 pounds per day or 100 pounds per hour. Thus the LAER, offsets, and related conditions do not apply to the smaller plants.

The application of these requirements to refinery expansions or modifications must be closely examined. Under the EPA Interpretative Ruling a modification is subject to the requirements if it would increase emissions from the source by the amounts specified discussed above. Confusion may exist as to what is the "source." Often a large industrial plant may include numerous sources. If certain equipment in an existing plant is replaced, the new equipment may be subject to the nonattainment requirements (including the obligation to install LAER) even though there is a net reduction in total emissions from the overall plant. This result will occur if the new equipment constitutes a separate source, as distinguished from the facilities where the reductions are made.

Certain limited exemptions from the nonattainment requirements are provided for fuel switching in response to national energy requirements. The 1976 Interpretative Ruling allowed an exemption for conversions to coal only where facilities to use coal were in existence on December 21, 1976. The 1977 Amendments and the revised Interpretative Ruling expand the exemption to other cases where fuel switching occurs under force of federal law.

- Revision of Existing State Implementation Plans

Approval of new refineries in nonattainment areas after July 1, 1979, is tied directly to the development and approval of revisions in state implementation plans. As discussed earlier, the statute prohibits the construction of major new sources, such as a new refinery, in a nonattainment area if after July 1, 1979 the state implementation plan, meeting the requirements of the 1977 Amendments, has not been finally approved by the EPA.

- Permit Requirements

One change affected by the 1977 Amendments was to convert previous requirements for preconstruction review into a direct permit program. The statute specifies that each state must, prior to July 1, 1979, amend its implementation plan to require permits for the construction and operation of new or modified major stationary sources in any nonattainment area. The principal conditions for issuance of such a permit (which closely resemble those applied under the original EPA Interpretative Ruling) are as follows:

- net reductions in emissions,
- lowest achievable emission rate, (LAER)
- other sources within the state in compliance,
- applicable SIP is being carried out.

The permit program and procedures for nonattainment areas are discussed in the following section of this report.

4.2.8 PSD -- Nonattainment Overlap

Since the PSD and nonattainment programs each impose complex but different requirements for issuance of a preconstruction permit, the first question for a major project is to determine which requirements apply.

The basic rule is that PSD requirements apply in the areas where standards are being met, while nonattainment requirements apply where violations of the standards still continue. For this purpose every area must be treated as a subject to either the PSD or the nonattainment requirements -- there is no middle ground which is exempt from both sets of requirements.

To determine whether a particular location should be classified as attainment (and therefore under PSD) or nonattainment, the first reference should be to EPA's official listing of designations for all areas of the country initially published in the Federal Register on March 3, 1978. This resulted from an examination of air quality monitoring data and a survey of all areas conducted by the states and then reviewed and published by EPA pursuant to a specific directive of the 1977 Amendments. The listing therefore should indicate how every area is to be treated. A copy of this listing (40 CFR 81) can be found in Appendix D-5.

In the listing, areas may be shown as "Does Not Meet Primary Standards", "Does Not Meet Secondary Standards", "Cannot be Classified", or "Better Than National Standards". The nonattainment rules apply if an area is violating either primary or secondary standards, first two categories. The PSD rules apply if an area is within the national standards or if air quality data is insufficient to classify an area, the last two categories.

Unfortunately the March 3, 1978, listing and amendments thereto cannot be taken as definitive, since the data underlying such classifications upon which that listing was prepared in many cases were inadequate. Subsequent monitoring may indicate that the status of a specific area should be changed. In particular, the requirements under PSD call for continuous monitoring data as part of a permit application, such data may show that an area previously classified as PSD should be reclassified nonattainment, in which case the nonattainment requirements will be applied.

Another significant complication arises from "cross-boundary" effects. A new refinery located in a clean area (PSD area) may generate emissions that disperse into a nonattainment area, and if any such effects would be significant the refinery will have to comply with offsets requirements to assure that it will not aggravate the violation of standards within the nonattainment area. Similarly, a new source located in a nonattainment area might generate emissions that would adversely affect a clean air area, particularly if located near a Class I area. Though this possibility is more remote since compliance with the offsets limitations will mean that the new refinery will cause no net increase in total emissions, the possibility cannot be altogether dismissed until an examination is made of the dispersion of pollutants from the specific locations where the offsets will be achieved and where the new refinery will be built. EPA officials on a number of occasions have stated that these cross-boundary effects will frequently require new sources to be reviewed under both the PSD and the nonattainment requirements.

Another important consideration is that both PSD and nonattainment requirements are applied on the basis of individual pollutants. There will be many cases where a new plant is to be located in an area that is nonattainment for one pollutant, such as photochemical oxidants or particulates, but is attainment for other pollutants, such as sulfur dioxide. In any such case, the plant must run the ordeal to satisfy both the procedural and the substantive requirements under both programs.

The prospects for a new refinery being subject to both PSD and nonattainment are increased by the striking differences in the patterns of standards attainment for the various pollutants. Violations of the photochemical oxidants standard are widespread, covering large regions in the country, particulately in the Northeast. Violations of the particulate standard are more limited but still common, occurring chiefly in densely industrialized areas. Violations of the carbon monoxide and nitrogen dioxide standards, by contrast, are quite rare. Thus, it will normally happen that a refinery to be located in an area subject to nonattainment for certain pollutants will also be subject to PSD for other pollutants.

In sorting out which requirements apply, care must be taken as to which pollutants should be considered with respect to determining (a) whether emissions from the plant are sufficiently large for the plant to be classified as a major source and therefore subject to either the PSD or nonattainment review process, (b) whether the increment requirements under PSD or the offset requirements under nonattainment have been satisfied, and (c) whether BACT or LAER is satisfied.

For example, note that a refinery will be subject to the PSD review if it generates emissions exceeding the size cutoff for any pollutant regulated by the Act, whereas a source will come under nonattainment review only if its emissions exceed the size cutoff for the particular pollutant for which violations of the standards exist. Once within the review process, a large plant must satisfy an increment or air quality analysis under PSD for any pollutants for which it exceeds the size cutoff; under nonattainment, again the offsets will be required only for the pollutant for which the violation exists. In the application of control technology tests, the statute states that under PSD the BACT standard must be met for every pollutant regulated under the Act, but EPA has ruled that such standard must be met only for those pollutants exceeding the size cutoff; the statutory provisions concerning nonattainment do not specify whether LAER should apply to all pollutants, and it presumably will be applied only to those for which a violation exists.

One consequence of the fact that a new plant may be subject to both PSD and nonattainment review requirements is that in any such case it is likely that it will have to obtain its air quality permits from two different regulating agencies, one state and one federal. In most cases the nonattainment review is currently administered by the state agencies, whereas the PSD review is generally administered by EPA. The PSD regulations of EPA provide that where dual permits are required, EPA will wait to act until the state proceeding has been completed. Dual review situations pose substantially greater prospects for delay.

4.2.9 Citizen Suits

Section 304 of the Act provides incentive for enforcement of the Act's provisions. The Act authorizes any person(s) to commence civil actions against:

- any person (including the United States and any other governmental agency) who is alleged to be in violation of an emission standard or limitation under the CAA or an order issued by the EPA or a state with respect to a standard or limitation,
- any person who proposes to construct or constructs any new or modified major emitting facility without a permit required by either PSD or nonattainment plans or who is

alleged to be within violation of any condition of such permit, or

- the administrator (EPA) where there is alleged a failure of the administrator to perform any act or duty under this Act which is not discretionary with the administrator.

The district courts shall have jurisdiction to enforce such an emission standard or limitation, or such an order, or to order the administrator to perform such act or duty as the case may be. The court, in issuing any final order, may award the cost of litigation to any party whenever the court determines such award is appropriate. More detail is found in Section 304 of the Clean Air Act located in Appendix D-1.

4.2.10 Judicial Review

Because of the importance and the controversial nature of some of the EPA's regulatory decisions implementing the Clean Air Act, most decisions are challenged in court by environmentalists, by industry or both. Court decisions have played a crucial role in determining the direction of EPA's implementation of the Act as well as insuring that an adequate technical case has been made by EPA for regulation.

The 1970 Act required persons who wished to challenge an Agency action to file a petition for review in the appropriate Court of Appeals within 30 days after the action was taken. The courts have upheld this time limit on judicial review by dismissing late petitions. In the 1977 Amendments, Congress lengthened the deadline to 60 days. Congress also endorsed the absolute cutoff that bars attacks on a regulation, as a defense in an enforcement action if the issue could have been raised in the Court of Appeals. The 1977 Act also ratified a court's decision that, in order to get judicial review after the deadline, a person must petition the Agency showing new information not available when the EPA action was being developed.

Congress provided in the 1977 Amendments that EPA actions of national applicability and effect are to be reviewed in the Court of Appeals for the District of Columbia Circuit. This provision classified a growing body of judicial decisions and is important to EPA because issues often cannot be settled for years if petitioners may obtain review in a number of the eleven Courts of Appeals. Differences among the circuits are not unusual, and the only solution is U.S. Supreme Court review, which is a lengthy process.

There is a case which is proceeding during this writing that will affect the building of a new refinery or expansion of an existing refinery. This case, Alabama Power Company, et al., Petitioners, vs. Douglas M. Costle, as Administrator, Environmental Protection Agency, et al., Respondents, concerns the validity of the final regulations, 40 CFR 51.24, 52.21 (1976), promulgated by the Environmental Protection Agency on June 19, 1978, embracing the prevention of significant deterioration (PSD) of air quality in the nation's "clean air areas." These regulations are being reviewed by the EPA due to the Court decision on June 18, 1979.

Some of the major changes that can be expected due to this decision are as follows:

- Fewer new pollution sources are likely to be affected by the rules. Current regulations apply to PSD sources having the potential to emit equal to or more than 100 or 250 tons per year of a pollutant (depending on the source), before installation of pollution controls. Similarly, current regulations affecting new source review in non-attainment areas apply to new sources with the potential to emit 100 tons per year or more before application of control equipment. The Court ruled this invalid, saying the rules should apply only to sources exceeding the applicable tonnage after installation of controls.

- Due to a new definition of "modification," some existing sources making changes may not have to undergo PSD review as currently required. Presently, decreases in emissions are not allowed to offset concurrent increases in determining whether a source is subject to the rules. The Court said, in effect, that a modification of an existing source will be subject to review only if there is a net increase in emissions from that source. A source obtaining sufficient emission reductions within the source itself could therefore avoid the modification requirements.

- Coverage of different types of pollutants is expanded for PSD purposes. Air quality monitoring would now be required of all pollutants regulated under the Federal Clean Air Act, not just those pollutants covered by air quality standards under Section 109 of the Act, as is the case now. Pollutants presently covered by Section 109 are sulfur dioxide, particulates, carbon monoxide, nitrogen dioxide, ozone (smog) and lead. In addition, the requirement to install best available control technology (BACT) would apply to all pollutants regulated under the Act for which the new or modified source would have a significant net increase. The existing regulations restrict BACT applicability only to pollutants for which the source is major.

- The Court said that PSD regulations can apply to sources in nonattainment areas only if their emissions impact a clean area in another State. EPA believes that this restriction on applicability will not afford proper protection for areas whose air must remain virtually pristine under Federal law, many of which are located in or adjacent to nonattainment areas. Although the proposal conforms to the Court ruling, EPA has petitioned for reconsideration of this issue.

- EPA is proposing to continue applying its existing PSD and nonattainment regulations until today's amended rules become effective. Sources with PSD permits that might no longer be required under the new regulations may apply to have them rescinded after the new regulations become final.

Douglas Costle, EPA Administrator, stated that "a major impact of the proposed changes is that a fewer new sources will be subject to our (EPA) regulations. On the other hand, the proposed rules increase the number of pollutants that must be monitored and for which best available control technology must be applied. The proposals also make it harder for existing sources in dirty areas to avoid regulatory review when changes are made to their plant. These comprehensive changes will continue to insure the protection of national air pollution standards for public health and welfare." A copy of the decision can be found in Appendix D-2.

4.3 FEDERAL WATER POLLUTION CONTROL ACT

4.3.1 Summary

- Basic Requirements -- Federal law prohibits any discharge to public waters without a permit, and imposes stringent pollution control requirements on all discharges, whether existing or new. Requirements on new plants are generally quite similar to requirements on existing plant.

- New Source Performance Standards -- EPA has issued such standards for numerous industrial categories, in which refineries are included, defining the levels of pollution control required for new plants. The NSPS apply to plants if construction commences after the standards have been promulgated (or in some cases proposed). A new plant built in compliance with NSPS is entitled to ten years protection against tightening of requirements specified in its permit.

- Expansions -- Expansions are considered a new source and are subject to New Source Performance Standards for Refineries. These new standards are generally quite similar to existing standards.

- Discharges to Municipal Systems -- Plants discharging wastes into municipal systems do not require permits, but are subject to pretreatment requirements and also user charges.

- Water Quality Requirements -- In locations where the water quality standards are being violated, new barriers may arise against further industrial growth. Also in locations where the water quality is of high purity, barriers may also arise.

- Civil Suits -- Section 505 of the Clean Water Act provides additional enforcement by civil suits. These suits can be against either a discharger or against the EPA.

- Oil Spill Prevention and Liabilities -- The Clean Water Act requires a new refinery to submit a "Spill Prevention Control and Countermeasure Plan" within six months after the date of beginning of operation. The owner or operator of any source which an oil spill originates must report the spill and either contain and clean up the spill or pay the cost of the clean up efforts by the responsible government agencies.

- Proposed New Source Performance Standards -- On December 21, 1979, the EPA proposed new source performance standards for petroleum refineries. These proposals may have significant impact upon the industry, especially new facilities.

To summarize the Federal Water Pollution Control Act upon the siting process for a new refinery, a decision diagram has been developed and is shown in Figure 57 A-F. This figure shows the regulatory considerations and impacts faced by a potential new source. The permit requirements are discussed in the next chapter. This same decision process on the regulatory impacts for major modifications or expansions is presented in Figure 58 A-F.

FIGURE 57A FEDERAL WATER POLLUTION CONTROL ACT DECISION DIAGRAM FOR A NEW REFINERY

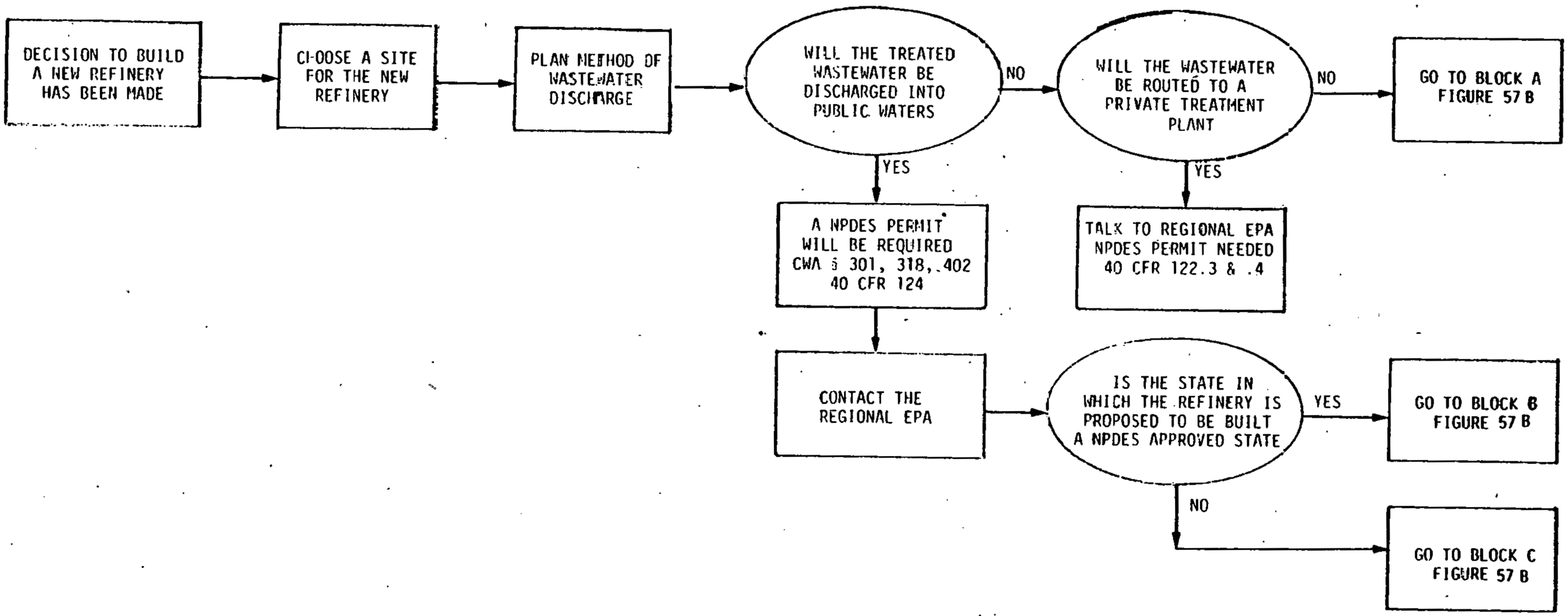


FIGURE 57B FEDERAL WATER POLLUTION CONTROL ACT DECISION DIAGRAM FOR A NEW REFINERY

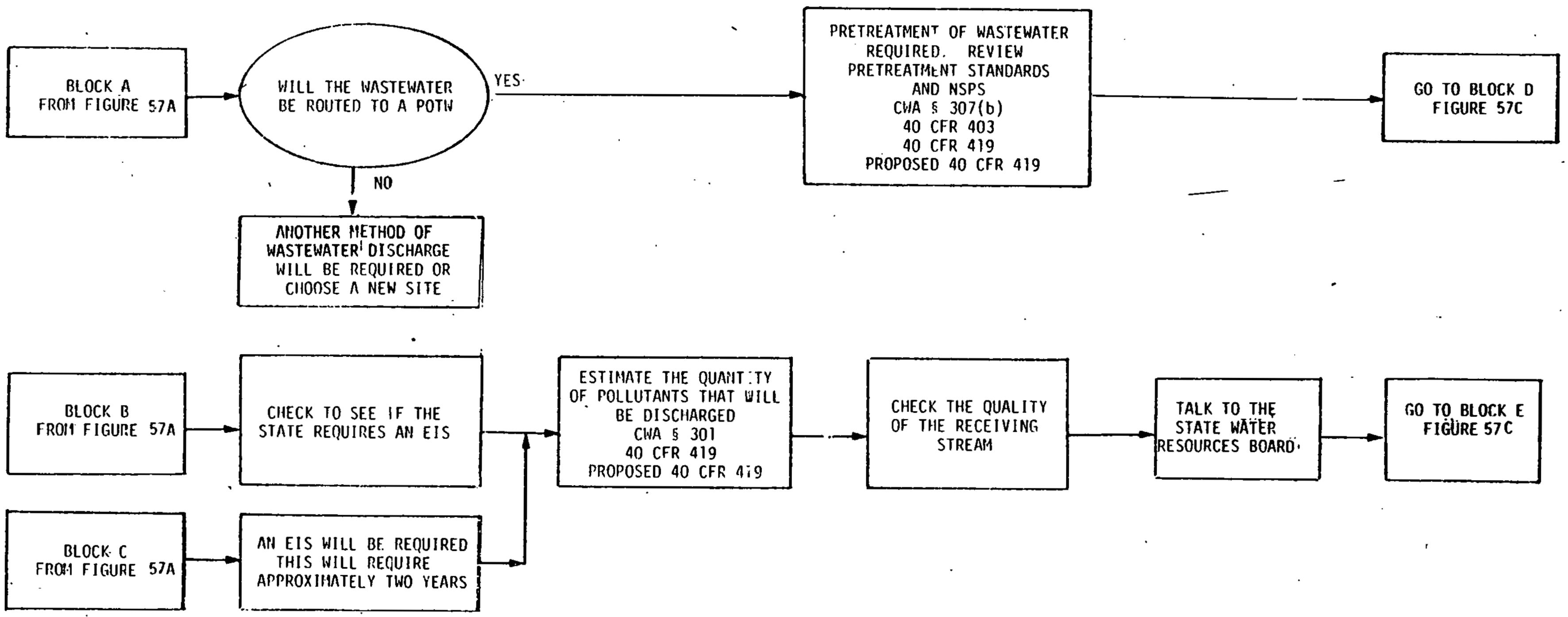


FIGURE 57C FEDERAL WATER POLLUTION CONTROL ACT DECISION DIAGRAM FOR A NEW REFINERY

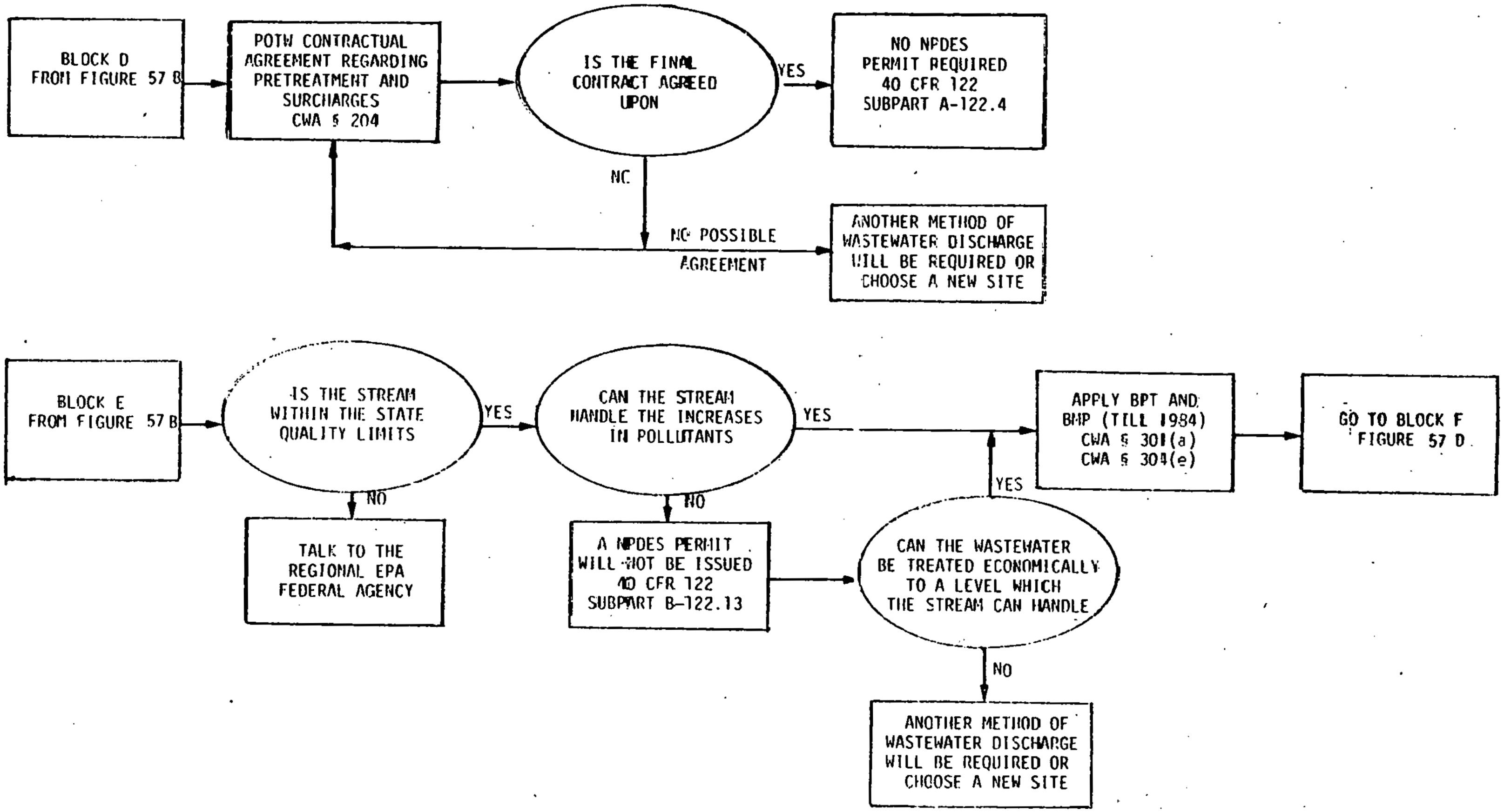


FIGURE 57D FEDERAL WATER POLLUTION CONTROL ACT DECISION DIAGRAM FOR A NEW REFINERY

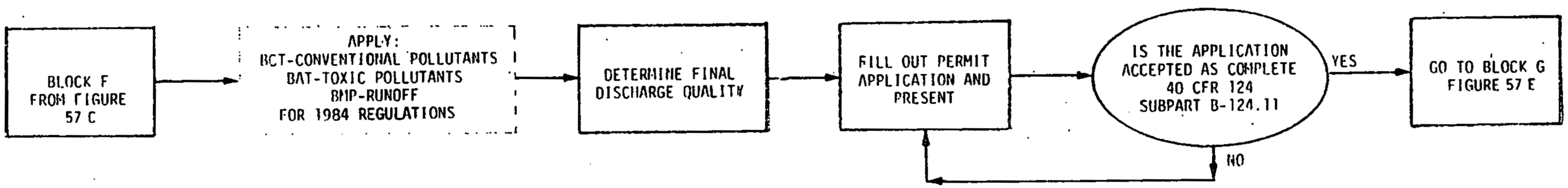


FIGURE 57E FEDERAL WATER POLLUTION CONTROL ACT DECISION DIAGRAM FOR A NEW REFINERY

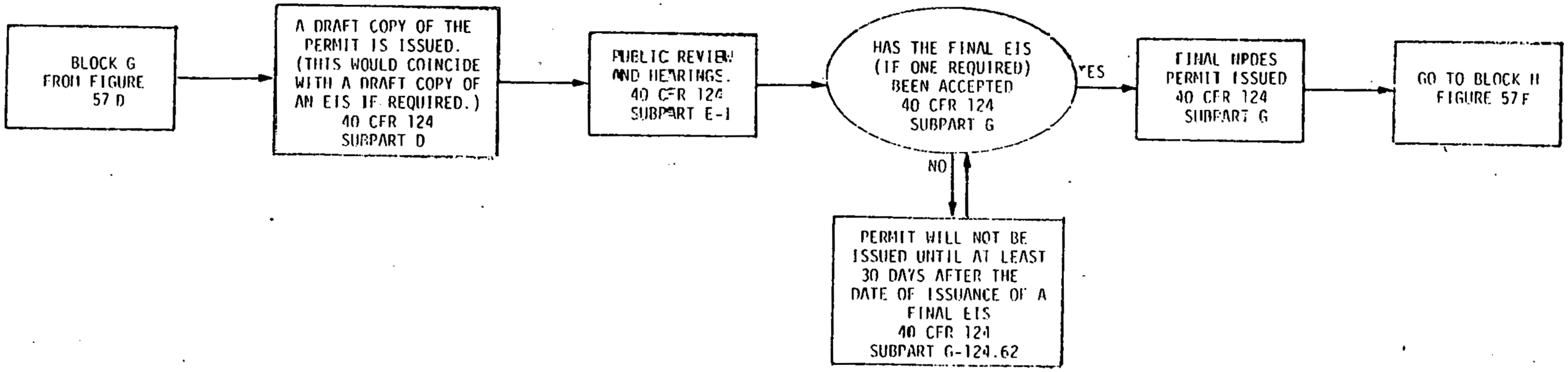


FIGURE 57F FEDERAL WATER POLLUTION CONTROL ACT DECISION DIAGRAM FOR A NEW REFINERY

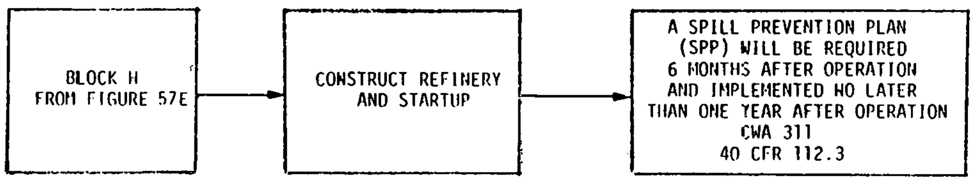


FIGURE 58A FEDERAL WATER POLLUTION CONTROL ACT DECISION DIAGRAM FOR EXPANSION/MODIFICATION OF A REFINERY

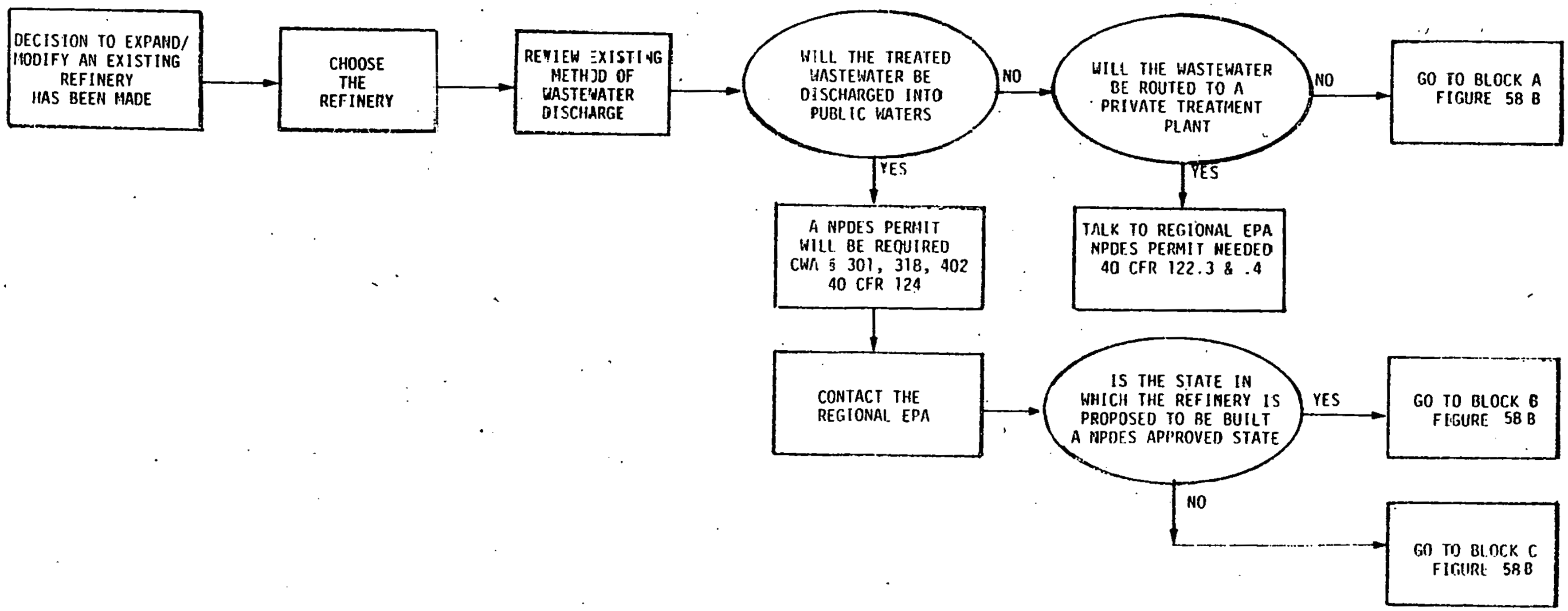


FIGURE 58B FEDERAL WATER POLLUTION CONTROL ACT DECISION DIAGRAM FOR EXPANSION/MODIFICATION OF A REFINERY

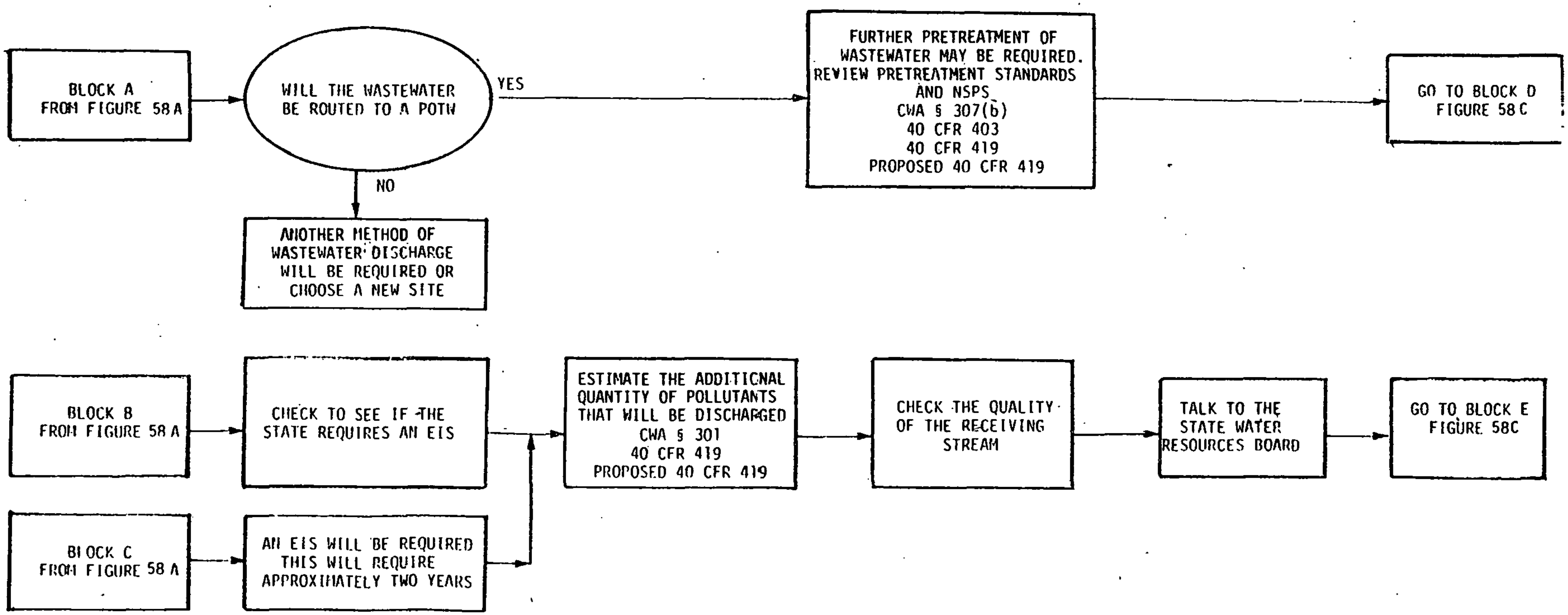


FIGURE 58C FEDERAL WATER POLLUTION CONTROL ACT DECISION DIAGRAM FOR EXPANSION/MODIFICATION OF A REFINERY

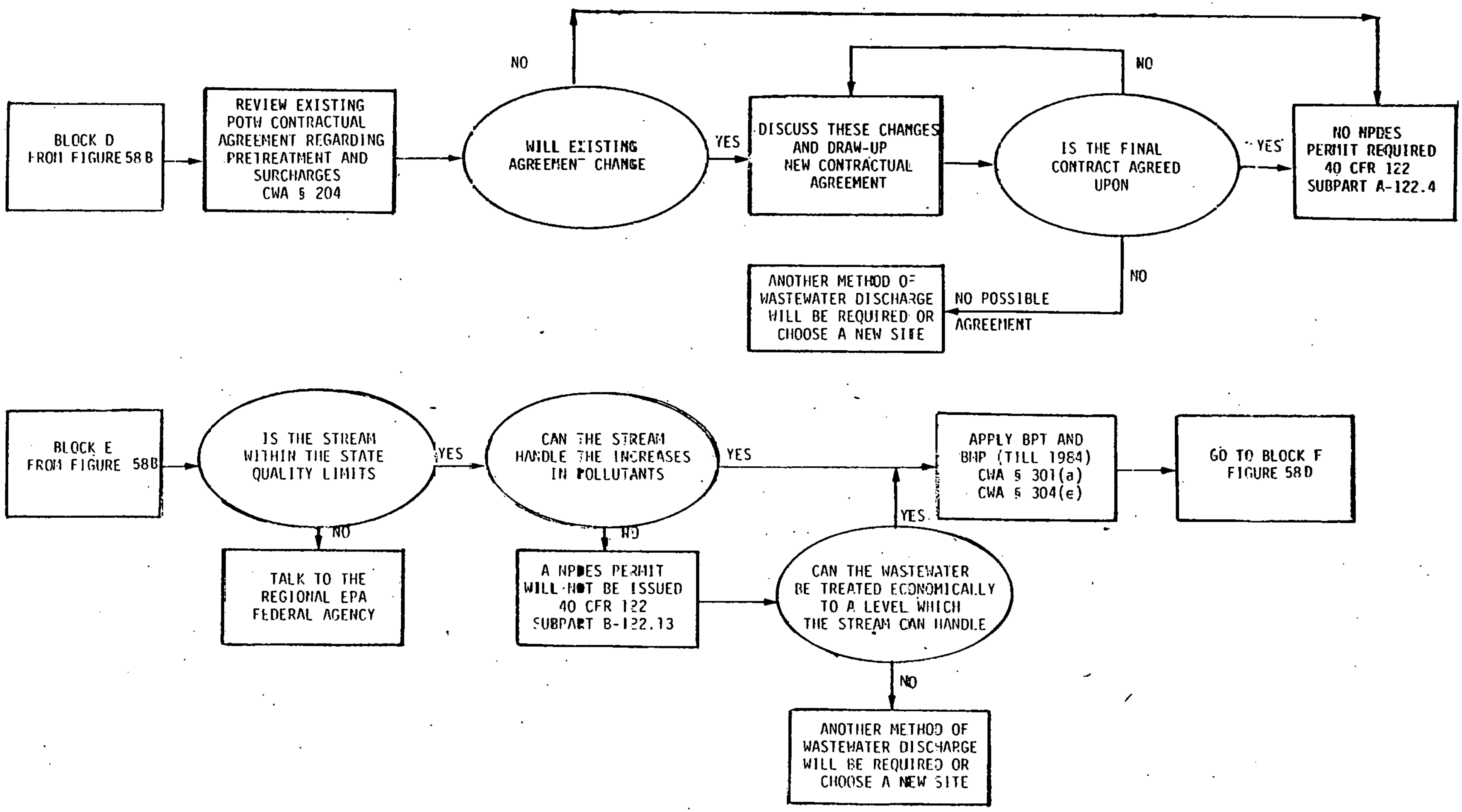


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FIGURE 58D FEDERAL WATER POLLUTION CONTROL ACT DECISION DIAGRAM FOR EXPANSION/MODIFICATION OF A REFINERY

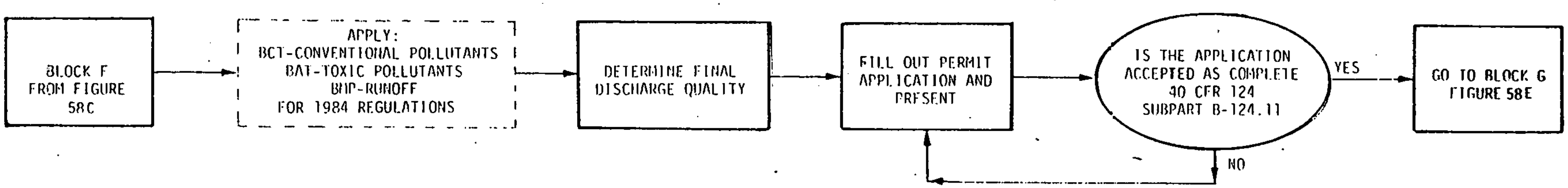


FIGURE 58E FEDERAL WATER POLLUTION CONTROL ACT DECISION DIAGRAM FOR EXPANSION/MODIFICATION OF A REFINERY

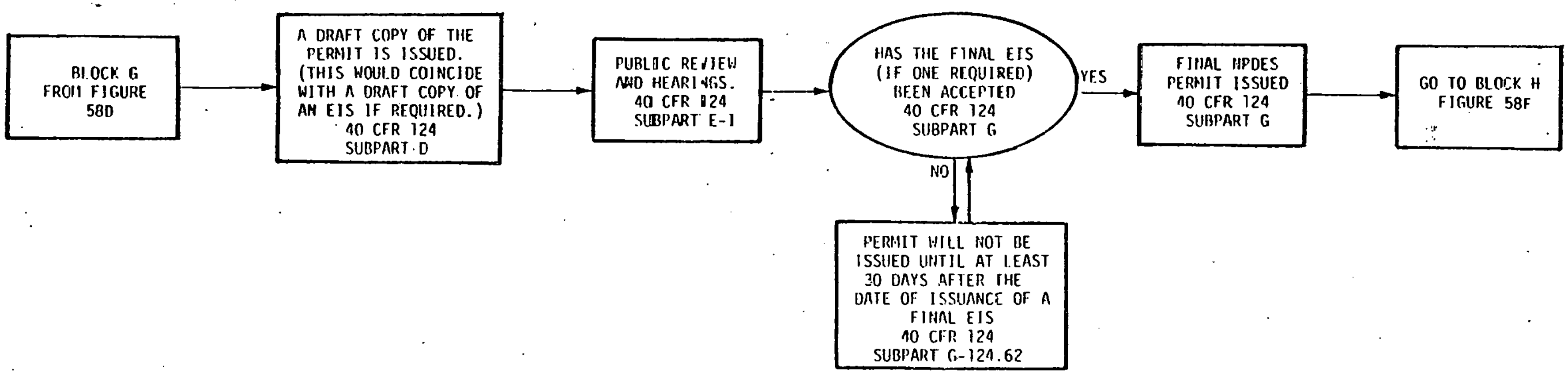
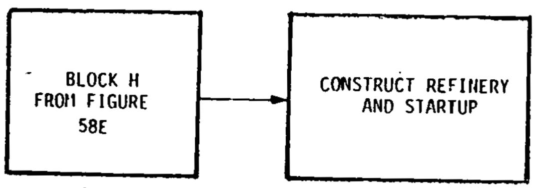


FIGURE 58F FEDERAL WATER POLLUTION CONTROL ACT DECISION DIAGRAM FOR EXPANSION/MODIFICATION OF A REFINERY



4.3.2 Introduction

The legal requirements established under the Federal Water Pollution Control Act, now more popularly called the Clean Water Act, do not present the same degree of regulatory complexities to the construction of new refineries or expansion of an existing refinery as do the corresponding provisions under the Clean Air Act. Nonetheless, the water pollution legislation does represent one of the major components of environmental law which must be satisfied in connection with any refinery construction.

Where the refinery meets the statutory definition of being a "new source," its pollution control systems must comply with specially established "new source performance standards" (NSPS). In some states, this new refinery may also be subject to the requirement of preparing an environmental impact statement. Where the new source performance standards are met, a plant may qualify for a ten-year protection against any tightening of the requirements, at least on those pollutants specifically covered by the permit. In expansion cases the principal water pollution concerns in connection with construction of a refinery will be simply to assure compliance with the same requirements which apply to existing refineries.

Some refineries discharge wastewaters into a municipal sewage treatment system. In new projects where this method is to be used, contractual arrangements must be developed with the local municipality, and the plant must comply with any applicable regulations requiring pretreatment of wastes, in addition to the treatment required by the municipal system. Also, the municipality must look at the design of the wastewater treatment plant to see if it can handle the increased capacity of water, pollutants, etc., and still meet discharge regulations set on them. Refineries, however, are more apt to discharge their wastes after treatment directly into a public waterway, and thus are known as a direct discharger. In this case, a discharge permit must be obtained, and the discharge is subject to extensive regulations.

Water pollution control requirements in the past have seldom presented any obstacle which might prevent construction of a new refinery or expansion of an existing refinery at a selected site. Discharge requirements for pollution control were incorporated into the design and construction of the facility. In the future that practice may or may not continue to apply. Some elements in the existing regulations could be applied in a manner which would block construction of a facility in certain locations.

4.3.3 The 1972 Water Act

The objectives of the Act are to "restore and maintain the chemical, physical and biological integrity of the Nation's water." The 1972 Act established standards of pollution control to be met by 1977 by all dischargers, whether existing or new. It also established more stringent standards of control to be met by 1983. Both sets of standards included a combination of "technology standards" and "water quality standards." The technology standards require every discharger to install by July 1, 1977, the "best practicable control technology" (BPT) and to install additional control equipment by July 1, 1983, representing the "best available technology economically achievable" (BAT). The 1972 Act also required that by the 1977 deadline each discharger must be in compliance with applicable water quality standards, which imposed a requirement for controls tighter than BPT in those localities where receiving waters were severely polluted. The Act tightened this receiving water reouirement for the July 1, 1983, deadline by specifying that no discharge should interfere with the use of any waterway for swimming or the protection of fish life, except in cases of extreme economic hardship. Another significant regulation under the 1972 Act requires many large industrial plants to adopt special plans for the prevention of oil spills, and EPA has proposed a similar program to prevent spills of hazardous substances.

In 1977 amendments to the Clean Water Act altered the 1983 requirements. Congress postponed the deadline to July 1, 1984, but no later than July 1, 1987, and replaced the single BAT limitation with a more complicated formula, applying a best conventional technology limitation (BCT) to certain conventional pollutants, a best available technology standard to toxic pollutants, and a best available technology limitation to certain other pollutants. The amendments also authorized, and EPA has proposed, additional regulation to require "best management practices" (BMP) to reduce runoff from plant operations. A copy of the Water Act can be found in Appendix E-1.

The framework for control of water pollution was to prohibit any discharge of pollutants into any public waterway unless authorized by a permit, with conditions to be set forth in the permit requiring adequate pollution control. The permit program was officially designated the National Pollutant Discharge Elimination System (NPDES).

Each state was given the option of developing its own NPDES program. Until a state has its own EPA-approved program, EPA grants the permits. After approval, the states grant the permits, with a review by EPA. So far, thirty-two of the states have developed their own programs. See Table 47.

The statutory standards are applied to individual plants through a two-step process. First, EPA has conducted an extensive program of issuing effluent guidelines, which define the technology standards for the refinery category and set numerical limits on the quantities of each pollutant which may be discharged by refineries per 1000 barrels of feed. Second, the limits set by these guidelines are pinpointed in reference to specific plants as the individual permits are issued, since the NPDES permits contain the ultimate definition of the responsibilities of each discharger. It should be noted that these permits also customarily include requirements that the operator of any plant regularly monitor its discharges recording the actual quantities of pollution discharged from the plant and submit reports to the agency.

Since these basic permit requirements apply to all dischargers, both existing and new, they are widely understood and are not apt to

TABLE 47

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

PERMIT STATES

The following states have received approval of their permit programs by EPA and have assumed responsibility for the issuance of NPDES permits:

Alabama	Montana
California	Nebraska
Colorado	Nevada
Connecticut	New York
Delaware	North Carolina
Georgia	North Dakota
Hawaii	Ohio
Illinois	Oregon
Indiana	Pennsylvania
Iowa	South Carolina
Kansas	Tennessee
Maryland	Vermont
Michigan	Virginia
Minnesota	Washington
Mississippi	Wisconsin
Missouri	Wyoming

Applicable Date: February, 1980

present major problems for a new refinery or expansion project, although new refineries or expansions do raise a few special complexities in the timing and processing of permit applications. This will be discussed in detail in the next chapter.

4.3.4 New Source Performance Standards

The first set of requirements under the Clean Water Act that apply specifically to a new refinery or expansion is the new source performance standards (NSPS). Section 306 of the Clean Water Act directed EPA to issue NSPS for the principal categories of industry, which petroleum refining is included (Table 48) and also defining the term "standard of performance." EPA has defined this meaning a standard for the control of the discharge of pollutants which reflects the greatest degree of effluent reduction which the Administrator determines to be achievable through application of the best available demonstrated control technology, processes, operating methods, or other alternatives, including, where practicable, a standard permitting no discharge of pollutants. These standards must be met by the new refinery or the permit will be terminated.

The standards have subdivided the petroleum industry into five refinery subcategories:

- topping
- cracking
- petrochemical
- lube
- intergrated

The EPA has established separate effluent limitations for each subcategory. Also under each subcategory, there are two sets of effluent limitations. One set of limitations is for refineries that are discharging into public waterways. The other set of limitations (pretreatment standards) is for refineries that discharge into the municipal sewer system and the publically owned treatment works plant treats the wastewater. The discussion in this section will be concerned with refineries that discharge into public waterways.

TABLE 48

NEW SOURCE PERFORMANCE STANDARDS ISSUED UNDER CLEAN WATER ACT

(Industrial Categories)**

- ASBESTOS
- BUILDERS PAPER AND BOARD MILLS
- CANNED AND PRESERVED FRUITS AND VEGETABLES
- CANNED AND PRESERVED SEAFOOD PROCESSING
- CEMENT MANUFACTURING
- DAIRY PRODUCTS PROCESSING
- FEEDLOTS
- FERROALLOYS
  - Open Electric Furnaces w/Wet Air Pollution Control Devices
  - Converted Electric Furnaces & Other Smelting Operations w/Wet Air Pollution Control Devices
  - Slag Processing
  - Covered Calcium Carbide Furnaces w/Wet Air Pollution Control Devices
  - Other Calcium Carbide Furnaces
  - Electrolytic Manganese Products
  - Electrolytic Chromium
- FERTILIZER MANUFACTURING
  - Phosphate
  - Ammonia
  - Urea
  - Ammonium Nitrate
  - Nitric Acid
  - Ammonium Sulfate Production
  - Mixed and Blend Fertilizer Production
- GLASS MANUFACTURING
- GRAIN MILLS
- HOSPITAL INDUSTRY
- INORGANIC CHEMICALS (PARTIAL LISTING)
  - Aluminum Chloride
  - Calcium Chloride
  - Hydrochloric Acid Production
  - Hydrofluoric Acid Production
  - Nitric Acid Production
  - Potassium Metal
  - Potassium Dichromate
  - Sodium Dichromate and Sodium Sulfate Production
  - Sodium Metal Production*
  - Sulfuric Acid Production*
  - Titanium Dioxide Production*
- INORGANIC CHEMICALS (CONTINUED)
  - Boric Acid Production
  - Chrome Pigment Production*
  - Copper Sulfate Production
  - Hydrogen Cyanide Production*
  - Iodine Production
  - Lead Monoxide Production
  - Silver Nitrate Production
  - Zinc Sulfate Production
- MEAT PRODUCTS
- MINERAL MINING
- NONFERROUS METALS
- ORGANIC CHEMICALS
- PAVING AND ROOFING MATERIALS
- PETROLEUM REFINING
  - Topping
  - Cracking
  - Petrochemical
  - Lube
  - Integrated
- PHOSPHATE MANUFACTURING
- PRINTING INK FORMULATING
- PULP PAPER AND PAPERBOARD MANUFACTURIN (PARTIAL LISTING)
  - Unbleached Kraft
  - Ammonia Base Neutral Sulfite Semi-Chemical
  - Unbleached Kraft-Neutral Sulfite Semi-Chemical
  - Paperboard from Waste Paper
  - Deink
  - NI Fine Papers
  - Papergrade Sulfite Market Pulp
- RUBBER MANUFACTURING
- SOAPS AND DETERGENTS
- SUGAR PROCESSING
- TEXTILE INDUSTRY
- TIMBER PRODUCTS PROCESSING

Applicable Date: December, 1979

*Proposed only
**Partial listing

The pollutants which the standards regulate at this time are:

- BOD_5
- COD
- TSS
- Oil and grease
- Phenolic compounds
- Ammonia expressed as nitrogen
- Total chromium
- Hexavalent chromium
- Sulfides
- pH

The standards give the limitation for each of the above pollutant except pH under each subcategory in terms of pounds per 1000 barrels of crude feedstock. The regulations contain both a daily maximum value as well as a 30-day running average maximum. The complete copy of these regulations can be found in the appendix. The amount of any one pollutant which can be discharged in one day for a subcategory can be determined by applying the following formula:

Mass Pollutant Limit = Unit Flow x Pollutant Limit x Unit Size Factor x Process Configuration Factor

where:

- Mass Pollutant Limit is in terms of pounds per day
- Unit Flow is in terms of 1000 barrels per day of feedstock to the refinery
- Pollutant Limit is in terms of pounds per 1000 barrels of feedstock for a subcategory such as cracking
- Unit Size and Process Configuration Factor can be found in 40 CFR 419.

A detailed example of this method is described in 40 CFR 419 subpart D which can be found in Appendix E-2.

An NPDES permit will, at minimum, require a facility to meet federal effluent standards as discussed above, but may impose more stringent limits, depending on the water quality standards that must be maintained in the receiving body of water (CWA 302). This is discussed in Section 4.3.8.

On December 21, 1979, the Environmental Protection Agency published in the Federal Register proposed Petroleum Refining Point Source Category Effluent Limitation Guidelines. These proposed regulations, if adopted and promulgated, will have significant impact upon the petroleum industry, especially new facilities. All governmental and industrial groups must be familiar with the implementation status and timing for these proposed changes so as to determine applicable discharge limits and impacts upon the design. Status of proposed regulations can normally be obtained from the staff of the Effluent Guidelines Division of the EPA in Washington, D. C. A copy of the proposed effluent limitations can be found in Appendix E-3.

4.3.5 The Ten-Year Protection Clause

One benefit to a refinery, available because of the language of the new source performance standards, is the ten-year protection clause. This provides, in general terms, that a new plant built in compliance with the current NSPS is to be protected against any tightening of the standards for a period of ten years after it commences operation, or for the period of depreciation or amortization under Sections 167 or 189 of the Internal Revenue Code, whichever is less.

A limitation on this ten-year protection is that it applies only to the pollutants specifically covered by the permit limitations and precludes only a tightening of those limitations through changes in the basic technology standards. A refinery could therefore find itself compelled to meet further limitations especially on toxic substances even during the period of protection.

An environmental impact statement would be required for a new refinery and possibly for an expansion or major modification.

The scope of the environmental impact statement and the procedures for its preparation follow the general pattern established in connection with the preparation of environmental impact statements by other federal agencies. The intricacies of this process, and the other federal statutes often brought into play through the environmental impact statement requirements are discussed in Section 4.1.

4.3.6 Expansion of Existing Sources

A question may arise in cases when a company is expanding an existing plant whether the change will cause the project to be treated as equivalent to construction of a new source and therefore subject to the legal requirements that apply to a new source. Current EPA regulations leave considerable uncertainty on this point, indicating only that the term "new source" includes any building, structure, facility or installation the construction of which is commenced after pertinent new source performance standards have been promulgated or proposed. Also, persons currently discharging who have existing permits shall submit a new application where facility expansion, production increases, or process modification will (40 CFR 122.1 (b) Subpart B):

- Result in new or substantially increased discharges of pollutants or a change in the nature of the discharge of pollutants, or
- Violate the terms and conditions of the existing permit.

A refinery which is planning an expansion should talk to the state agency or the EPA for clarification between a new source and expansion. The above two points would imply that an expansion of an existing refinery would be treated as a new source. See 40 CFR 122 located in Appendix E-4.

It may be advantageous for a refinery to contend that an expansion should be treated as a new source. Although one would anticipate that new source performance standards would impose far more costly control requirements than standards applied to existing sources, in actual practice the new source performance standards frequently are no more severe. Thus, if it is clear that no EIS requirements will apply, and if the new source performance standards would not impose significantly greater costs, classification of a project as a new source would give the refinery the benefit of the ten-year protection clause against tightening of the control requirements. The actual advantages or disadvantages may vary considerably from case to case, and accordingly the refinery should make an individual analysis in reference to each expansion project.

4.3.7 Industrial Use of Municipal Treatment Facilities

An important choice to be made in connection with a new project is whether the wastewaters will be treated entirely at the plant and discharged directly into a public waterway or whether the wastewaters will instead be discharged into a municipal sewage treatment plant system. The opportunity to use a municipal system and the implications of deciding to do so may be a major factor in corporate siting decisions. The considerations bearing on that factor can be difficult to evaluate, particularly as the costs of pollution control continue to rise and the requirements applicable to users of municipal systems undergo significant change.

Refineries discharging into municipal systems (public owned) are exempt from the Federal permit requirements but are covered by the NPDES permit for the public owned treatment work. Far less pressure has been exerted on these refineries to require costly controls over their discharges compared to refineries that are required a NPDES permit. The 1972 Act, however, contains two types of authority which in future years may significantly change the balance of advantage for a refinery using a municipal system. First, the law required municipalities receiving federal grants for the construction of their treatment plants to impose substantial charges on their industrial users. Second, the law also required such companies to meet "pretreatment" standards with respect to any pollutants which might interfere with, pass through, or be incompatible with the municipal treatment works.

EPA has moved slowly in the promulgation of pretreatment programs by municipal systems to effectively enforce the pretreatment standards which have been issued. Not until June 26, 1978, did EPA finally promulgate its basic regulations to specify the type of pretreatment programs municipal systems should adopt. In future years, however, the application of pretreatment requirements may profoundly change the comparative costs for industry of discharging wastes into a municipal system.

The underlying principle upon which the pretreatment standards are being developed is to assure that the discharges from a municipal system accepting wastes from an industrial plant will be treated to the same degree as if the industrial wastes were treated at the site to regulatory limits and discharged directly into public waters. This is accomplished by setting the pretreatment standards at levels comparable to the limitations on direct dischargers, subject to a credit for the extent of removal of specific pollutants actually achieved by the municipal treatment plant receiving wastewaters from an industrial user. The impact of this approach is that where critical pollutants from an industrial plant receive little or no effective treatment once they enter the municipal system, the industrial plant must provide the full treatment itself, imposing the same financial burden on it as though it were a direct discharger. In addition since the wastes do pass through the municipal system, the company will be required to pay user charges representing its proportional share of the costs of operating and maintaining the municipal system (CWA 204 (b). See Appendix E-6.

Refineries that are discharging into a privately owned or a CO-OP owned treatment plant are exempt from the federal permit requirements. The private or CO-OP treatment plant has to apply and receive a NPDES permit for operation. This only applies if the refinery discharges through pipes, sewer, or other conveyances that lead to the treatment plant. For more detail, see 40 CFR 122 and 125 in Appendix E-4 and E-7.

4.3.8 Prohibition of New Plants

Beyond questions as to the type and cost of pollution controls required in the design of a new plant, the more fundamental question is whether the water quality regulations might actually prevent construction of a plant at a proposed site. It is clear that these regulations do not present anywhere near the same type of potential obstacles as are presented by the Clean Air Act. Nowhere in the field of water pollution control is there a system of preconstruction approval to match the PSD and nonattainment procedures of review. Except in a few cases, the working assumption of water pollution controls has been that while they will affect matters of how a new plant is built, they will not impact questions of whether or where a new plant is built. This pattern of past practice can be relied upon as a general guide to the future, but with important exceptions.

The most significant situation in which water pollution requirements may threaten to prevent construction of new plants concerns grossly polluted water bodies where the water quality standards are currently violated. It should be noted that since the permit requirements were first established in the 1972 Act, the law has required any applicant for a permit from EPA to provide a certification by the state water pollution control agency that the discharge will not violate water quality standards, and in a similar manner the EPA regulations have required state agencies in issuing permits to assure that any discharge allowed will comply with water quality standards. This legal framework would appear to lay the same type of foundation upon which the nonattainment preconstruction review program was developed for new sources of air pollution, although to date no such system has evolved under the water pollution statute.

The potential for evolution of the water pollution requirements toward prohibition of certain new plants is accentuated by the revised NPDES regulations. In the section entitled "Prohibitions" is a provision stating that no permit shall be issued to a new source or new discharger (expansion) if it will cause or contribute to the violation of water quality standards. Moreover, the regulation would put a burden of proof upon a permit applicant to demonstrate that the new plant will not result in a violation of water quality standards, and in any case where a new plant would be located on a "water quality limited segment," the applicant would also have to demonstrate that there are sufficient remaining pollutant load allocations to cover the new discharge.

This last new requirement could revolutionize the procedures for issuance of NPDES permits to new sources. The reference to any water quality limited segment would embrace large portions of waterways throughout the country, wherever existing pollution sources (whether industrial, municipal, agricultural, or natural) cause a violation of water quality standards requiring more stringent controls than merely application of the BPT (or perhaps BAT) technology standards. In these areas, typically waste load allocations have been made requiring extra controls by dischargers sufficient to achieve the water quality standards, but not necessarily providing any margin for additional growth. Thus, the stage would be set for application of the same type of offsets policy as developed in the nonattainment program under the Clean Air Act.

The other situation in which water quality considerations might block approval of a new plant would involve water bodies of high water quality. This situation immediately invites comparison to the areas of pristine air quality, Class I Areas, for whose protection the PSD program has been developed. Information concerning water quality can be found in the appendix.

4.3.9 Planning

The possibility that enforcement of the water quality standards might evolve in the direction of prohibiting new plants is further increased by work currently in progress to prepare areawide waste treatment management plans under Section 208 of the Clean Water Act. Under this program hundreds of millions of dollars of federal money have been granted to local planning agencies or to state agencies to conduct extensive programs for water quality planning. The nature of individual planning efforts has varied from one locality to another, but in many areas major efforts have been funded to collect data on the existing condition of water quality. In some cases wasteload allocations are being adopted which may allocate the entire assimilative capacity of a particular water body leaving little or no margin for future growth. Elsewhere these plans may determine that the pristine character of certain streams or lakes should be permanently preserved and prohibit major industrialization in such areas.

4.3.10 Citizen Suits

Section 505 of the Act provides an incentive for enforcement of the Act's provisions. The Act authorizes any person(s) having an interest which is or may be adversely affected to commence civil actions either against a discharger, for violation of any effluent standard or limitation under this Act, or against the EPA, for failure to enforce the Act's provisions. Experience under the Refuse Act program indicates that civil suit provisions are effective in enforcement of the Act's provisions.

The district courts shall have jurisdiction to enforce such an effluent standard or limitation, or such an order, or to order the EPA to perform such Act or duty and to apply any appropriate civil penalties under Section 309(d) of this Act. The court, in issuing any final order, may award cost of litigation to any party whenever the court determines such award is appropriate.

4.3.11 Oil Spill Prevention and Liability

Section 311 of the Act requires a new refinery to submit a Spill Prevention Control and Countermeasure Plan (SPCC Plan). This plan shall be prepared within six months after the date of beginning operation and shall be fully implemented as soon as possible, but not later than one year after operation commences.

The facility shall contain appropriate containment and/or diversion structures or equipment to prevent oil from reaching any navigable water. Some of the possible systems would be:

- Dikes, berms, or retaining walls sufficiently impervious to contain any spilled oil
- Curbing
- Culverting, gutters, or other drainage systems
- Weirs, booms, or other barriers
- Spill Diversion ponds
- Retention ponds
- Sorbent materials

The plan also addresses the facility drainage system, and bulk storage tanks. Failure to prepare and maintain a plan in accordance with the regulations subjects the violator to civil penalties of up to $5,000 for each day of violation. Similar, but more stringent, planning and accident avoidance requirements are applicable under Coast Guard regulations governing vessels and oil transfer operations associated therewith.

If, despite compliance with the spill avoidance procedures discussed above, a spill does occur, additional obligations arise.

The owner or operator of the source from which the discharge originates must immediately report the discharge to the Coast Guard and/or EPA. Failure to comply with this requirement results, upon conviction, in a fine of up to $10,000 and/or imprisonment for not more than one year. It should be kept in mind that this reporting requirement is broadly construed and may apply to oil spills which originate several miles inland e.g., if the spill goes into a storm sewer which outlets to navigable waters.

In addition to giving notice, the discharger must either contain and clean up the spill or pay the cost of clean up efforts by the responsible governmental agencies. Section 311 (f) limits the discharger's liability for the government's actual removal costs to $50 million unless there is willful negligence or willful misconduct in which case there is no limit on liability. EPA is authorized to establish lower limits of liability for facilities having small storage capacity (1000 barrels or less). Generally, effective private clean up measures are less costly than similar efforts by the government and, in addition, those efforts are of considerable practical importance in mitigation of the civil penalties discussed below.

The discharger's final obligation is to pay a civil penalty of not more than $5,000 for each spill. Although the Coast Guard (which is the agency administering the penalties section) must assess a penalty, it has considerable discretion to reduce the amount of the penalty based on the size of the business of the discharger, the effect of the penalty on his ability to continue in business, and the gravity of the violation. The Act provides the right to notice and a hearing in connection with civil penalty assessments, and there had been case law to the effect that the notice given by the discharger must not be utilized as a means of obtaining information to serve as the basis for assessing a civil penalty. More information on oil spills can be found in 40 CFR 112 located in Appendix E-6.

4.4 RESOURCE CONSERVATION AND RECOVERY ACT

4.4.1 Introduction

The disposal of solid wastes in the past has typically presented no regulatory obstacles to the siting and construction of a new refinery. That day could be over.

In 1976 Congress passed the Resource Conservation and Recovery Act (RCRA). Under that law EPA is currently establishing a new regulatory framework. This will include certain controls on the disposal of virtually any form of solid waste, and it will concentrate specifically on the disposal of a hazardous waste.

Controls on the disposal of hazardous wastes will be among the most important future developments in the field of environmental regulations. Because these controls are still in an early stage in their formation, they cannot be described in detail. It will be critical to the planning of any new refinery, however, to try to anticipate the new requirements which may be confronted. A brief review of the principal features set by the statute and by EPA's draft and proposed regulations will provide some helpful clues. A copy of the Resource Conservation and Recovery Act can be found in Appendix F-1.

The basic approach of the statute is to divide the regulation of solid wastes into two categories -- hazardous wastes and other solid wastes. Although the regulation of hazardous wastes is more important, it will be easiest to discuss the non-hazardous wastes first. The approach to these other solid wastes is to focus on the disposal sites, establishing a legal distinction between a sanitary landfill and an open dump. The Act directs EPA to promulgate criteria for classification of an approved disposal facility as a sanitary landfill. Meeting classification criteria will assure that there will be no reasonable probability of adverse effects on health or the environment. Although EPA has not yet promulgated such criteria, they probably will be designated to prevent leaching, runoff of ground water, open burning, and other potential environmental problems.

Every site for the disposal of solid waste which does not qualify as meeting the EPA definition of a sanitary landfill is automatically defined by the statute as an open dump. The statute directs EPA to prepare an inventory listing of every open dump in the United States, and it further directs that within five years thereafter every open dump must either be closed or upgraded to meet the sanitary landfill criteria. Each state is called upon to develop a plan to carry out this program, and the state agencies will bear sole responsibility for enforcement of these requirements.

For hazardous wastes the statute establishes a far more ambitious regulatory program. A central feature will be a manifest system through which every load of hazardous waste material can be tracked from its origination at the plant of a generator through the hands of each transporter to its ultimate disposition at a disposal site. The statute also creates a new permit program to cover every hazardous waste disposal site, under which detailed requirements for handling and control of such wastes will be imposed on the operators of such facilities.

The purpose of this cradle-to-grave system of manifests and permit program is to carry accountability for the final disposal of hazardous wastes back to the industry which created them. This will transform the previous situation in which some industries have been able to hire an independent contractor to haul away their wastes and then forget about it.

4.4.2 Definition of Hazardous Wastes

The extensive controls to be established over the handling of hazardous wastes place great importance on the definition of that term, a matter of extreme complexity. The statute itself defines the term "hazardous waste" as "a solid waste, or combination of solid wastes, which because of its quantity, concentration, or physical, chemical, or infectious characteristics, may....pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed." It is important to note that the statute also defines "solid waste....including solid, liquid, semisolid, or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations...." although the statute does specifically exclude from the definition wastewater discharges subject to NPDES wastes pollution permits. The effect is to cover, as one example, liquid wastes permanently stored in lagoons.

The statute requires EPA to promulgate criteria for identifying hazardous waste and to promulgate regulations identifying the characteristics of hazardous waste and listing particular hazardous wastes. In approaching this task, EPA has been influenced by the fact that the risk presented by a particular waste is a function of the combinations and concentrations of its hazardous constituents. It therefore has developed a series of tests to be applied to each waste stream rather than relying solely on an identification and quantification of individual hazardous substances contained in the wastes.

On December 18, 1978, EPA proposed regulations establishing the following four basic criteria for identification of a hazardous waste:

- ignitability,
- corrosiveness,
- reactivity, and
- toxicity.

Under this approach, a waste stream would be declared hazardous under the ignitability test if, while in a liquid state, it has a flash point of less than 60° Centigrade, is an ignitable compressed gas, or is an oxidizer. It would be covered by the corrosiveness test if it is aqueous and has a pH of less than or equal to three or more than or equal to 12 or has a corrosion rate of more than one-quarter inch per year on steel at a test temperature of 130° Fahrenheit. Similar tests would be applied under the reactivity criteria.

Toxicity is apt to be the most significant criteria. This would classify as hazardous a waste containing any substance for which an EPA Primary Drinking Water Standard has been established if its concentration, when measured by a specified toxicant extraction procedure, is ten times greater than the drinking water standard. Those standards set extremely low limits and cover many substances (arsenic, barium, cadmium, chromium, lead, mercury, selenium, silver, endrin, lindane, methoxychlor, toxaphene, 2, 4-D, and 2, 4, 5-TP Silvex). These limitations are shown in Table 49. The reach of this criterion therefore would extend to many types of industrial waste.

The proposed regulations would also establish a second parallel system for classifying wastes as hazardous. This covers the waste streams from a long list of specified industrial activities. EPA proposed a list of 158 specific wastes which are presumed to be hazardous and will be regulated as such unless the generator can demonstrate that such waste does not meet the criteria. Thus a first step for any company concerned with these regulations would be to check the list of wastes presumed to be hazardous to see whether it covers operations found in a refinery. This list can be found in the proposed regulations located in Appendix F-2.

The total coverage of wastes which would be classified as hazardous under the proposed regulations is vast. EPA estimates that approximately 35 million tons per year would be regulated, originating from approximately 270,000 generators and involving approximately 10,000 transporters.

4.4.3 Permits

Regulations will also establish a new permit program. This program will focus on industrial plants which produces a hazardous waste. If the proposed refinery does not produce a hazardous waste, then it will be exempt from the permit process.

TABLE 49

NATIONAL INTERIM PRIMARY DRINKING WATER STANDARDS AT TOXIC LEVELS[1]

Contaminant	Extract Level, Milligrams per Liter
Arsenic	0.50
Barium	10.0
Cadmium	0.10
Chromium	0.50
Lead	0.50
Mercury	0.02
Selenium	0.10
Silver	0.50
Endrin (1, 2, 3, 4, 10, 10-hexachloro-6, 7-epoxy-1, 4, 4a, 5, 6, 7, 8, 8a) octahydro-1, 4-endo, endo-5,8 di methano naphthalene	0.002
Lindane (1, 2, 3, 4, 5, 6-hexachlorocyclo hexane gamma isomer	0.04
Methoxychlor (1, 1, 1-trichloroethane). 2, 2,-bis [p-methoxyphenyl]	1.0
Toxaphene ($C_{10}H_{10}Cl_8$-technical chlorinated camphene, 67-69% chlorine)	0.050
2, 4-dichlorophenoxyacetic acid (2,4-D)	1.0
2, 4, 5-TP Silvex	0.10

[1]The extract levels specified for the above substances are equivalent to 10 times the National Interim Primary Drinking Water Standard.

4.5 WETLANDS AND COASTAL ZONE

4.5.1 Introduction

Many refineries are located beside major water bodies, either for transportation purposes or to obtain a supply of process water, and from an economic viewpoint it will often be advantageous for a refinery either to expand facilities at such a plant or build a new plant in a similar location. In such cases, the new refinery may be subject to special regulations designed to protect wetlands or to control development within the coastal zone.

A permit must be obtained from the Corps of Engineers for any project which will involve any dredging or filling of wetlands. The two principal reasons a company might wish to use wetlands are (1) to obtain space for the location of new facilities, or (2) to install docks or other waterfront structures needed for transportation or other water-dependent uses. Details on the permits can be found in another section of this report.

The second important federal program concerning land which may affect a new refinery is the Coastal Zone Management (CZM) Act. Under this law, states are developing plans to regulate growth within the coastal zone (which includes areas bordering on the Great Lakes). Where such plans have been adopted, they may impose a variety of new requirements on a refinery project.

4.5.2 Coastal Zone Management Act

In 1972 Congress enacted the Coastal Zone Management Act to stimulate land use planning and controls in coastal areas. Although implementation of this program has evolved slowly and its impact has seldom been felt to date, it promises to become a factor affecting any future refinery development in a coastal location.

The statute was enacted in response to studies of the destruction of estuarine and other shoreline areas. It reflected a Congressional recognition that intense competition for use of coastal areas was producing a tangle of conflicts that were not being resolved satisfactorily through existing mechanisms. A major purpose of the legislation was to provide greater protection for marine resources and related ecological values. The approach adopted was to provide federal grants as a voluntary inducement to the development and adoption of state management programs. Federal responsibility was vested in the Secretary of Commerce, who delegated it to the Office of Coastal Zone Management in the National Oceanic Administration.

To qualify for federal grants (up to 80 percent of the costs of both developing and administering the coastal zone management program) a state program must be approved as meeting specified federal criteria. The program must include the following elements:

- An identification of the boundaries of the coastal zone;
- A definition of what shall constitute permissible land and water uses;
- An inventory of areas of particular concern;
- An identification of the means by which the state proposes to exert control over the land and water uses;
- Broad guidelines on priority of uses in particular areas; and
- A description of the organizational structure proposed to implement the management program.

When the coastal zone management programs are put into effect, they represent a new component of the regulatory framework to be faced by any company planning refinery project near the coastal area. They may, or may not, add additional permit requirements. They invariably will strengthen the involvement of state and local governmental units in the review of construction proposals. They normally will tilt that review in the direction of stronger environmental protection. Finally, no required federal permit or approval of a project can be granted if it would violate requirements under an approved state coastal zone management program. A copy of the CZMA can be found in Appendix G-1.

4.5.2.1 Definition of the Coastal Zone

The coastal zone will not include extensive areas of land even in the coastal states. It is generally limited to a narrow band of land within the immediate vicinity of the coastline. The statute defines "coastal zone" as including "the coastal waters ....and the adjacent shorelands... strongly influenced by each other and in proximity to the shorelines of the several coastal states, and includes the transitional and intertidal areas, salt marshes, wetlands, and beaches."

A precise definition of the coastal zone in any specific locality can be obtained by consulting the plan adopted for that state. In this regard the plans for various states differ marginally from each other. A basic approach taken by many state plans is to define the landward edge of the zone as a specified distance (for example, 100 ft, 300 ft, or 1000 ft) from the mean high water mark. Another common technique has been to define the zone as including the area between the shoreline and the nearest major road, railroad, or public utility line. The boundary is usually adjusted to include in the coastal zone any coastal marshes, coastal flood plains, tidal rivers, or other areas where vegetation is affected by saline water.

The coastal zone extends seaward (by statute) to the outer boundary of the territorial sea, normally three miles from the shoreline. Major islands or peninsulas may be included in their entirety, including for example all of Cape Cod in Massachusetts. The coastal zone program includes all states bordering the Atlantic and Pacific Oceans, the Gulf of Mexico and the Great Lakes. In the Great Lakes states the coastal zone extends to the international boundary between the United States and Canada.

4.5.2.2 Status of Implementation

Progress in implementing the Coastal Zone Management Act initially was slow. As of January 1, 1978, over five years after passage of the Act, full management programs had been approved for only three states: Washington, Oregon and California. Washington state was the first state to have the required plan approved by the Secretary of Commerce A copy of the plan is located in Appendix G-2. There has been 15 programs that have been approved as of January 1, 1980. The status of all coastal states and their plans can be found in Table 50.

Prior to the passage of the federal act, the State of Delaware passed the Delaware Coastal Zone Act of 1971. This act requires special affirmative siting legislation for any major industrial facility within a two mile strip of land along its entire coastline. This act should be carefully reviewed by any refiner considering a project within the State of Delaware.

4.5.2.3 Principal Features of State Programs

The dominant feature of state management programs is that they do not contain final determinations of the uses of land to be permitted in designated areas. Instead they merely establish the mechanisms for future government decisions on proposals for development on a case-by-case basis. The state programs are all quite precise in defining the boundaries of the coastal zone itself, and many of the plans provide for the designation of certain areas having special environmental importance where industrial development would be prohibited. In most parts of the coastal zone, however, questions as to what type of development should be allowed are left for future decision.

STATUS OF STATE COASTAL ZONE MANAGEMENT
PLANS AS OF JANUARY 1, 1980

State	Approved Plan
Alabama	X
Alaska	X
California	X
Connecticut	
Delaware	X
Florida	
Georgia	
Hawaii	X
Illinois	
Indiana	
Louisiana	1
Maine	X
Maryland	X
Massachusetts	X
Michigan	X
Minnesota	
Mississippi	
New Hampshire	
New Jersey	2
New York	
North Carolina	X
Ohio	
Oregon	X
Pennsylvania	
Rhode Island	X
South Carolina	X
Texas	3
Virginia	
Washington	X
Wisconsin	X

1. Plan expected to be approved sometime in 1980.
2. Only portions of the full plan approved.
3. Plan expected to be approved some time in 1981.

The CZM Act does require that each state adopt a scale of priorities for use of coastal areas. These priorities are apt to discourage industrial development. In some state programs a top priority is placed on protecting natural resources with minimum interference from human activity. To the extent that refinery development may be permitted, state programs are apt to rank development proposals on the basis of whether they present a need for coastal location. The Washington program established a strong preference for water dependent uses, thus providing more opportunity for approval of an industrial development which cannot exist in any location other than at the shoreline, (such as a marina), while practically shutting the door against approval of projects which could locate equally well away from the shoreline.

4.5.2.4 General Effect

Whenever a company proposes to build a new refinery within an area covered by an approved coastal zone management program or involves the use of wetlands, it should give a top priority to discussing its plans with the staff of the state agency and exploring all requirements which will apply under that program. Moreover, unless the refinery presents an apparent need for a coastline location or need for use of "wetlands" it would generally be better to select a site outside the coastal zone.

4.6 TOXIC SUBSTANCES CONTROL ACT

4.6.1 Introduction

Prior to the passage of the Toxic Substances Control Act (TSCA) in 1976, significant gaps existed in the federal government's authority to test and regulate problem chemicals. The Clean Air Act (Section 112) and the Federal Water Pollution Control Act (Section 307), deals with chemical substances when they enter the environment as wastes (emissions to the air or discharges to the water). In many cases controls could not be easily fashioned or required without severe economic consequences. Toxic substances legislation, which provides testing well before a chemical reaches the production phase, overcomes this difficulty.

Other statues, such as the Occupational Safety and Health Act and Consumer Product Safety Act, deal only with one phase of the chemical's existence (worker exposure or direct consumer exposure) and contain no authority to address environmental hazards. While both of these statutes are clearly needed, the life cycle of a chemical, from production to ultimate disposal, provides many opportunities for its escape into the environment and for human exposure, and federal authority to deal with that overall cycle is fragmented. The Toxic Substances Control Act is designed to fill these gaps, both in regulatory powers and authority to require that tests be conducted before the environmental or human exposure occurs.

The Toxic Substances Control Act has two main regulatory features:

- acquisition of sufficient information by EPA to identify and evaluate potential hazards from chemical substances, and
- regulate the production, use, distribution, and disposal of such substances where necessary.

The important provisions of TSCA which could affect a new refinery or expansion of an existing refinery are briefly described below. A copy of the Act can be found in Appendix H-1.

4.6.2 Premarket Notification

The heart of TSCA is the requirement for premarket notification (PMN). Under Section 5, a manufacturer must notify EPA at least ninety days before producing a new chemical substance, defined as any chemical not listed on a specially compiled inventory list (discussed later). This notification is also necessary even for older chemicals, already on the inventory list, if the administrator concludes that there is a significant new use which increases environmental or human exposure. In either case, EPA may extend the notification processing period by an additional ninety days, but the reasons for requiring longer considerations may be challenged in court.

4.6.3 Inventory List

Because the notification rules apply primarily to new chemical substances, there must be a list available of pre-existing chemicals. Under Section 8(b), EPA is required to compile an inventory of chemicals manufactured or processed in the United States. This does not cover every chemical ever produced but is limited to these substances produced within the three year period preceding the promulgation of applicable regulations, namely since January 1, 1975.

EPA intends to update the inventory list periodically to include products for which notification forms have been submitted. A company planning to construct a new refinery could consult the revised list and know if premarket notification would be required.

This list is available from the EPA and currently contains approximately 50,000 chemicals. Because of the size of the list, contained in six volumes, it has not been included in the Appendix. This list is available by ordering Document Number GPO-055-007-00004-7 and GPO-055-007-0003-9 for volumes 1-4 and 5 and 6, respectively. The address is as follows:

Superintendent of Documents
Government Printing Company
Washington, D.C. 20402.

4.6.4 Priority Listing

Section 4(e) of the Act provides for a priority list of chemicals for testing and directed that the list "may not, at any time, exceed 50." The act allows for expansion of this list within this 50 by allowing substances and mixtures. As of December 7, 1979, there were 31 chemicals on this list. These are listed in Table 51 and can be found in Appendix H-2.

The chemicals on the priority list are then tested according to Section 4(a) and (b) of the Act. From these test results, if there may be any reasonable basis to conclude that these chemicals could cause harm, appropriate action will be taken to reduce any possible harm.

These appropriate actions may include limiting the amount that can be produced, prohibiting or limiting specific uses considered most hazardous, requiring labels and warnings, mandating extensive manufacturing and monitoring records, controlling disposal, "or otherwise regulating any manner or method of commercial use of each substance or mixture." Restriction may even be applied to some geographical areas and not others. Quality control on manufacturing or processing may be applied for a highly toxic compounds.

TSCA should have little impact on the siting construction, or operation of a refinery. Still, a company planning to build a new refinery should check the priority list of chemicals to be reviewed. If any of the chemical s) that are planned to be used, or produced, are on this list, the company can expect standards or limitations set for that chemical.

TABLE 51 THE TSCA SECTION 4 (e) PRIORITY LIST

	Designated for action by
Acetonitrile	April 1980
Acrylamide	April 1979**
Alkyl epoxides	October 1978*
Alkyl phthalates	October 1978*
Aniline and bromo, chloro, and/or nitroanilines	April 1980
Antimony (metal)	April 1980
Antimony sulfide	April 1980
Antimony trioxide	April 1980
Aryl Phosphates	April 1979**
Benzidine-based Dyes	November 1980
Chlorinated benzenes, mono- and di-	October 1978*
Chlorinated benzenes, tri-, tetra- and penta-	October 1979
Chlorinated naphthalenes	April 1979**
Chlorinated paraffins	October 1978*
Chloromethane	October 1978*
Cresols	October 1978*
σDianisidine-based Dyes	November 1980
Dichloromethane	April 1979**
1,2-Dichloropropane	October 1979
Cyclohexanone	April 1980
Glycidol and its derivatives	October 1979
Halogenated alkyl epoxides	April 1979**
Hexachloro-1,3-butadiene	October 1978*
Hexacholorocyclopentadiene	April 1980
Hydroquinone	November 1980
Isophorone	April 1980
Mesityl oxide	April 1980
4,4'-Methylenedianiline	April 1980
Methyl ethyl ketone	April 1980
Methyl isobutyl ketone	April 1980
Nitrobenzene	October 1978*
σTolidine-based Dyes	November 1980
Polychlorinated terphenyls	April 1979**
Pyridine	April 1979**
Quinone	November 1980
Toluene	October 1978*
1,1,1-Trichloroethane	April 1979**
Xylene	October 1978*

*Designated by the Committee in its First Report (2) and responded to by the Administrator in 43 FR 50134-50138.
**Designated by the Committee in its Second Report (3) and responded to by the Administrator in 44 FR 28095-28097.

4.7 OTHER FEDERAL REGULATIONS OF CONCERN

4.7.1 General

The regulations that have been discussed in detail above, namely: National Environmental Policy Act, Clean Air Act, Clean Water Act, Resource Conservation and Recovery Act, Wetlands and Coastal Zone Act, and the Toxic Substances Control Act are a few of the regulatory programs that would affect a company planning a new refinery or an expansion of an existing refinery. A partial list of other regulatory programs and their main concerns are as follows:

- Ports and Waterways Safety Act of 1972 - concerned with the prevention of damages to vessels, bridges, or any other structure on navigable waters or any land structures adjacent to those waters.

- Marine Protection Research, and Sanctuaries Act of 1972 - concerned with the transporation for dumping and the dumping of material into ocean waters.

- Safe Drinking Water Act - concerned with the quality of water for domestic use.

- Deepwater Port Act of 1974 - concerned with the procedures for the location, construction, and operation of deepwater ports.

- Noise Control Act of 1972 - concerned with sources of noise and the control of noise from these sources.

- Marine Mammal Protection Act - concerned with certain species and population stocks of marine mammals that are endangered due to man's activities.

- Endangered Species Act of 1973 - concerned with various species of fish, wildlife, and plants that are in danger of extinction. A partial list of these species has been included in Appendix I.

- Wild and Scenic Rivers Act - concerned with certain rivers that possess outstandingly remarkable scenic, recreational, geologic, fish and wildlife, historic, cultural, or other similar values. A list of these rivers are presented within the Act which can be found in Appendix I.

- Occupational Safety and Health Act (OSHA) - concerned with the safety and health of people.

The first page of these acts can be found in Appendix I of this report In the next section of this handbook, the permits required by these regulations and the procedures for obtaining these permits are presented.

5.0 PERMITTING ACTIVITY

5.1 FEDERAL PERMITS

The Federal regulations that apply to a new refinery and an expansion or major modification of an existing refinery are complex as may be described in Section 4. These regulations describe preliminary procedures and environmental documents, what a company can discharge into a receiving stream or emit to the atmosphere, how they can dispose of solid wastes, and implications about the difficulty of site selection or growth potential. One thing that the regulations have in common is they require an approval or permit before construction can start or operation can begin.

These approvals or permits can be categorized into five areas, namely,

- water - concerned with discharges, oil spills, navigation aids, and impacts upon navigable waters.
- air - concerned with emissions in clean and nonattainment air regions, the quantity of emissions, and the net quality of the air after construction.
- land - concerned with disposal of solids (hazardous and non-hazardous), uses of coastal land, wetlands, and flood plains.
- health and safety - concerned with such areas as underground injection quality, noise, and air quality and conditions of working areas.
- miscellaneous - concerned with such areas as construction in navigable water, archeological findings, endangered species (plants or animals), right-of-ways, electronic transmitting equipment, air navigation aids, and wild and scenic rivers.

One of the most important questions regarding permits is the length of time to secure all of the required permits. If a company waits too long to apply for the permits, a costly delay in construction or operation could occur. However, if they apply too early, there is a chance of a permit expiring necessitating reapplication under new conditions. A company can estimate the permitting process lasting 3 to 5 years including monitoring, the preparation of both an environmental assessment and the lead agencies environmental impact statement and public hearings.[87-88] The degree of controversy is a difficult and intangible factor to include in the project planning.

The possible permits and the issuing agency that a company planning a new refinery, major modification or expansion would be required to obtain are listed in Table 52. The addresses and telephone numbers of the issuing agencies are listed in Table 53.[88]

A company should review this list of possible permits to determine the applicable permits for their project. After that, the issuing agencies should be contacted at the very beginning of the permit process. This initial contact can be used to determine if the permit is applicable and, what information is required to obtain the permit. Once this required information has been gathered by studies or engineering design, the company is prepared to apply for the permit when the project schedule suggests this action.[89-92]

While all of the permits listed are important, there are three which need special note. These are the National Pollution Discharge Elimination System (NPDES) permit, required under the Clean Water Act and the Prevention of Significant Deterioration (PSD) and the nonattainment permits required under the Clean Air Act. Without applicable permits, a company cannot start construction or operation of the proposed facility Information regarding the other permits can be found in Appendix J and by contacting the issuing agency.

TABLE 52

REQUIRED FEDERAL PERMITS

WATER RELATED PERMITS

Permit	Issuing Agency	Comments
1. National Pollutant Discharge Elimination System (NPDES)	EPA	a. Must have before construction if EIS required, or b. Must apply for at least 180 days before operations. Includes time required for permit preparation and approval. c. Copy of permit located in Appendix
2. Spill Prevention Control and Counter Measure Plan	EPA	a. Not an actual permit but a requirement of the CWA. b. Should not be required for an expansion c. Plan must be submitted no more than 6 months after operations begin. d. See 40CFR 112 in Appendix E-6.
3. Permit for Discharge of Dredged or Fill Material into Navigable Waters	ACOE	
4. Permit for Transportation of Dredged Material for Dumpting into Ocean Waters	ACOE	
5. Aid to Navigation Agreement	Coast Guard	a. Must have before construction. b. Install buoys, markers, etc.
6. Permit for Private Projects to Improve Navigable Waters	ACOE	

AIR EMISSIONS PERMITS

Permit	Issuing Agency	Comments
1. Prevention of Significant Deterioration Permits	EPA	a. Permit Requirements: • 1 year of monitoring • Will not violate increment or air quality standard • Installation of BACT • Postconstruction monitoring • Public review
2. Nonattainment Permit	EPA (Issued by State Agency Usually)	a. Permit Requirements; • Offsets • LAER • Other sources in compliance • SIP being carried out • Public review

TABLE 32 (Cont'd)

LAND USE PERMITS

Permit	Issuing Agency	Comments
1. Coastal Zone Management (OSM)	NOAA	a. Handled by the state.
2. On-Site Treatment, Storage, and Disposal of Solid Waste	EPA (RCRA)	b. Must be in compliance with RCRA and proposed rules.
3. Approval to Construct Meteorological Tower	FAA	
4. To Construct a Bridge over Navigable Waters (pipelines)	Coast Guard	
5. Permit for Construction or Operation of a Deep Water Port	Coast Guard	
6. Permit for Activities in Designated Marine Sanctuaries	NOAA	
7. Permit for Causeways	Coast Guard	

HEALTH AND SAFETY PERMITS

Permit	Issuing Agency	Comments
1. Occupation Safety and Health Administration (OSHA)	DOL	a. Must have before start of construction. b. Sets limits on: • Noise • Air Quality in work area • Working Conditions
2. Underground Injection	EPA	a. See Safe Drinking Water Act of 1974

TABLE 52 (Cont'd)

MISCELLANEOUS REQUIRED PERMITS

Permit	Issuing Agency	Comments
1. Permit to Construct or Work in Navigable Waters	ACOE	a. Must have before start of construction. b. A copy of the permit can be found in Appendix J.
2. An Archeological Survey of the Proposed Site	NPS	a. Must have before start of construction (The National Park Service administers the archeological preservation Act of 1974 and the Historic Preservation Act of 1966.
3. A Survey of the Proposed Site and surroundings for any plants and animals on the Endangered Species list.	FWS	a. The U.S. Fish and Wildlife Service (FWS) (Department of Interior) administers the Endangered Species Act of 1973.
4. Provide an Analysis of Need for a New Refinery	DOE	a. Needed for Environmental Impact Statement
5. Construction of Pipeline across Navigable Waters	ACOE	a. Must have before start of construction.
6. Certification of the Oil Receiving Facility	DOT	a. DOT - Custom Service b. Required if receiving foreign oil c. Required before receiving foreign oil shipments
7. Air Navigation Approval	FAA	a. Must file on all construction in excess of 200 ft adjacent to an airport or flight corridor. b. Must have before construction.
8. License to Operate Electronic Transmitting Equipment	FCC	a. Required if using any transmitting equipment such as VHF paging equipment

TABLE 53

LOCATION OF FEDERAL PERMIT ISSUING AGENCIES

DEPARTMENT OF AGRICULTURE

Independence Avenue
between 12th and 14th St., S. W.
Washington, D. C. 20250
(202) 655-400

Agricultural Stabilization and Conservation Service

Administration Building, Jefferson Dr.
between 12th and 14th Sts., S. W.,
Washington, D. C. 20250
(202) 447-3467

Forest Service

South Building
12th St. and Independence Ave., S. W.,
Washington, D. C. 20013
(202) 447-6661

Soil Conservation Service

South Building
12th St. and Independence Ave., S. W.
Washington, D. C. 20250
(202) 447-4531

DEPARTMENT OF COMMERCE

Commerce Building
14th St. between Constitution Ave.
and E St., N. W.,
Washington, D. C. 20230
(202) 377-2000

National Oceanic and Atmospheric Administration

11400 Rockville Pike
Rockville, MD 20852
(301) 443-8910

DEPARTMENT OF DEFENSE

The Pentagon
Washington, D. C. 20301
(202) LI5-6700

DEPARTMENT OF DEFENSE (cont'd

Army Corps of Engineers

Department of the Army,
Forrestal Building
Washington, D. C. 20314
(202) 693-6456

DEPARTMENT OF ENERGY

Forrestal Building
1000 Independence Ave., S. W.
Washington, D. C. 20545
(202) 252-5000

ENVIRONMENTAL PROTECTION AGENC

Waterside Mall
401 M St., S. W.
Washington, D. C. 20460
(202) 755-2673

DEPARTMENT OF HEALTH, EDUCATIO AND WELFARE

200 Independence Ave., S. W.
Washington, D. C. 20201
(202) 245-6297

Health Services Administrati

5600 Fishers Lane
Rockville, MD 20857
(301) 443-2216

DEPARTMENT OF INTERIOR

Interior Building
Washington, D. C. 20240
(202) 343-1100

DEPARTMENT OF INTERIOR (cont'd)

Fish and Wildlife Service

Interior Building
Washington, D. C. 20240
(202) 343-4717

Bureau of Land Management

Interior Building
Washington, D. C. 20240
(202) 343-5101

National Park Service

Interior Building
Washington, D. C. 20240
(202) 343-8067

Heritage Conservation and Recreation Service

440 G St., N. W.
Washington, D. C. 20243
(202) 343-5741

Bureau of Reclamation

Interior Building
Washington, D. C. 20240
(202) 343-4157

Bureau of Mines
Columbia Plaza
2401 E. St., N. W.
Washington, D. C. 20241
(202) 634-1004

Office of Water Research and Technology

Interior Building
Washington, D. C. 20240
(202) 343-5975

DEPARTMENT OF LABOR

New Labor Building
200 Constitution Ave., N. W.
Washington, D. C. 20210

DEPARTMENT OF LABOR (cont'd)

Occupational Safety and Healt Administration

New Labor Building
200 Constitution Avenue, N. W
Washington, D. C. 20210

DEPARTMENT OF STATE

2201 C Street, N.W.
Washington, D. C. 20520
(202) 655-4000

DEPARTMENT OF TREASURY

Customs Service
1301 Constitution Ave., N. W.
Washington, D. C. 20229

DEPARTMENT OF TRANSPORTATION

400 7th Street, S. W.,
Washington, D. C. 20590
(202) 426-4000

U. S. Coast Guard

400 7th Street, S. W.
Washington, D. C. 20590
(202) 426-2390

Federal Aviation Administratic

800 Independence Ave., S. W.
Washington, D. C. 20590
(202) 426-8058

WATER RESOURCES COUNCIL

2120 L St., N. W.
Washington, D. C. 20037
(202) 254-6303

Special mention is necessary to reference new activity at the federal level to consolidate the permitting procedures. Hearings were sponsored by the EPA to review permit consolidation during 1979. These ideas were favorably received and if properly implemented might assist both the new refinery or the major modification of the existing facility. Further assistance in the areas of timing and review may also be offered by the Energy Mobilization Board, an administrative attempt to "fast track" important energy projects. Both these programs may prove beneficial but their impact within the federal permitting process is far too uncertain at this time.

5.1.1 National Pollutant Discharge Elimination System Permit

The framework for control of water pollution was established by the Federal Water Pollution Control Act. The main thrust of that legislation was to prohibit any discharge of pollutants into any public waters unless a permit has been issued. This permit program was designated as the National Pollutant Discharge Elimination System (NPDES).

The NPDES permit contains the final definition of the water quality limitations that a new refinery or expansion of an existing refinery can discharge. These discharge limitations are based on the new source performance standard (NSPS) for refineries and the water quality standards of the receiving streams. These standards are discussed in Section 4.3 of this document and can be found in Appendix E.

One of the major considerations of a company planning to construct either a new refinery or expand an existing refinery is the timing and processing of the permit application. The exact time of when to submit the NPDES permit application is dependent upon the need for an environmental impact statement (EIS).

When an EIS is required, the permit application must be applied for and received before the start of construction. The normal time to complete the EIS process is approximately two years. A company should apply for the NPDES permit concurrently with the EIS process.

If an EIS is not required, the NPDES permit program states that a company proposing a new discharge shall submit an application at least 180 days in advance.[73] This period is designed to allow adequate time for determining the limitations and processing the permit. The optimum timing for this application would be determined on a case-by-case basis after discussions with the involved agency and reviewing project schedule concerns. Copies of the required permits and an instruction manual are found in Appendix J.

5.1.2 Federal Air Permits

There are two Federal air permits that a company considering a new project must be aware of and take into full account. These are the Prevention and Significant Deterioration (PSD) permit and the Nonattainment permit. Of all the possible Federal permits required for a new refinery or expansion of an existing refinery, these two permits can be most complex, time consuming, and costly. The regulations leading up to the permitting process were discussed in detail in Section 4.2.

A company planning to construct a new refinery or expand an existing refinery in an area where the ambient air quality is as good or better than the National Ambient Air Quality Standards must follow a specific federal regulatory program called Prevention of Significant Deterioration (PSD).

PSD requires preconstruction approval of any new refinery or major modification or expansion of an existing refinery to be built in an attainment area. The requirements of this preconstruction approval are as follows (CAA 165):

- monitoring at the proposed site for approximately one year (may not be required)
- submission of air quality and other pertinent data
- demonstrate that the refinery will not violate any applicable increment or air quality standards
- installation of Best Available Control Technology within the design of the refinery
- public review and hearings concerning the project
- commitment to conduct postconstruction air monitoring

Upon the completion of these requirements, a construction permit is issued for the project.

Projecting the time required for approval under PSD is, at best, complicated. It will vary greatly depending upon such factors as the time to turn in a "complete" application, whether one year of monitoring is required, and the amount of public comments, hearings, and controversy. For a project where monitoring is not required and very few public comment are received, the process can take approximately twelve months. If the project does require monitoring and extensive public hearings, the process time will take a minimum of 24 months with no projected upper limit.[37-38]

For EPA, Region IX, a copy of a PSD application, general procedures and time requirements can be found in Appendix J.

While the PSD program deals with projects located in attainment areas, there is also a regulatory program which deals with projects planning to locate in areas not meeting the National Ambient Air Quality Standards. This regulatory program is the nonattainment program which is administered by the state under its implementation plan.

Like the PSD program, the nonattainment program requires a company to obtain a project permit before construction can start. Before obtaining this permit, the company must satisfy five preconstruction requirements. These requirements are as follows (CAA 173):

- the anticipated emissions must be offset with an applicable amount as to provide a net air quality benefit - offsets
- each source must use controls to obtain the lowest achievable emission rate - LAER
- all other sources owned by the company in the proposed state are in compliance with the regulations
- the applicable SIP is being carried out
- the 1979 SIP has been approved by the EPA
- public review and hearings are complete

The time required for approval of the construction permit is based upon how long it takes to satisfy the preconstruction requirements. For a refinery, major modification, or expansion which would not require a significant amount of offsets or the offsets are easily obtainable and the public comments and hearings were minimal, the time required would be approximately 12 months. However, in the more likely example for a refinery or expansion which would require a significant amount of offsets which are not easily obtainable and the project receives numerous public comments, the time required could range upwards from twelve months to several years.[29-32]

EPA Region IX nonattainment application requirements, procedures and time requirements can be found in Appendix J.

5.2 STATE PERMITS

The identification of state permits required for the sitting of an oil refinery or major modification has become better organized because of the number of similar environmental protection laws that apply to all of the states. The workbook attempts to define several basic types of permits. Each state has been set aside with a specific table which identifies the governor's name, the address, and the personal contacts that should be made. Each state's table is categorized under five basic headings:

- Water
- Air
- Health and Safety
- Land
- Miscellaneous

For water permits, many of the states are covered by the National Pollutant Discharge Elimination System (NPDES) of the U.S. Environmental Protection Agency. At this time, 32 of the states are in this category. Water permits are the most uniform permit procedures in the country. Those states that do not have NPDES permits are moving toward getting EPA approval. Responsibility for air permits is divided between the EPA and the state depending upon ambient air quality for the site under consideration for the refinery project. In the attainment regions, the permits are administered by the federal agencies. In the nonattainment areas, the states retain the permit authority.

Under health and safety, the permits are generally established by the individual state regulations. The workbook also identifies the Occupational Safety and Health Act (OSHA) contact point for each state so that any requirements under this state administered regulation can be understood.

The fourth permit area of land use was found to be quite variable in application. The Department of the Interior does not have a listing of contact points for each state. The Governor's Office could be contacted early in a project to determine specific requirements. Under miscellaneous permits, the workbook has grouped together all of the additional permits that states have identified.

Under each permit category, additional information listed includes the address of the issuing agency that would have responsibility for the permit review, the type of application under the general heading, and the name address, and the title, if available, of the state officer responsible for that permit.

It is difficult under the procedures used for this survey, to obtain from each state complete identification of all their permit requirements. In developing these requirements, a thorough research format was sent to each individual state asking them to completely define all of the permits that might come under these categories when reviewing a major refinery project. After selecting the states of interest, the refiner should be able to identify some of the permit requirements, be able to contact the Governor's Office and, if necessary, the individual state offices that have responsibility for these permits.

In Appendix L, selected information from the state survey responses have been tabulated to show the scope of the permitting process. Each site must be carefully considered for these energy projects to determine the complexity of the permit procedures and identify possible roadblocks to acceptable environmentally sound development.

The permit areas that are presented in the state tables represent the most significant requirements for the siting of new refineries and major expansions. There are additional state organizations that do affect the potential for the project development. These might be referred to as passive areas because they deal with such things as economic development, bonding procedures, tax write-offs, etc. Their support often plays a major role in project acceptance.

In many instances, local governments have very little knowledge of what state attitudes are on industrial permitting and environmental control. The siting of these major facilities is not a common occurence. The Mayor of a community should be able to review the state format and go directly to the agency and seek the requirements with which they would have to deal. The Mayor would have easy reference to the key people in the state who have the requirements for the key permitting requirements. They would be able to contact the Director of specific state agencies and initiate information exchange. Too often our individual local communities have difficulty at the start of an industrial inquiry because they just don't know who to go to for information. The ability to look through the workbook and cover the regulations and permits of the federal government as well as the permits that are administered by the state government should make the start of the local review that much easier.

In summary, the state permit tables[54-103] identifies the governor, the issuing agencies for the key permit areas, the type of permit requirements and the name and address of the person responsible for these permits. This whole series of charts will provide the kind of quick resource for the individual planning a refinery project. Communication can quickly establish credibility so important to support for a major energy project.

5.3 LOCAL PERMITS

Local governments are having continuing problems in dealing with energy related programs. The siting of new industrial plants, like new petroleum refineries, is a complex issue because of the increasing amount of regulatory and permitting activities that must be considered.

Without question, it is much more difficult to identify the permits that are required at the local level. Since there are few areas in the thousands of local jurisdictions across the country that have dealt with permitting of chemical processes, there is not a great deal of organized requirements. It is difficult to get permitting information on all of the varying types of local government. The workbook is developed so that any elected official or industry representative can use it as a means to determine permitting requirements and to develop guidelines for the siting of a new refinery or the expansion of an existing refinery.

The history of local government is substantially different than that of state government. The uniformity that exists at the state level does not exist in the area of local jurisdictions. The local government can take on several forms such as:

- Strong Mayor - in which the appointments and management of the city jurisdiction is under the direction of the chief elected official.
- Weak Mayor - council form of government in which the management and leadership roles are diversified.
- City Manager - Town Manager - form which consists of hired professional management teams.
- There are also several forms of government which are unique to certain sections of the country due primarily to historical reasons. Such as the town meeting in New England, the Parrish style of Louisiana, the county government in the West and others makes it impossible to have a systematic approach to dealing with permitting requirements.

As evidence, review of the research formats that were circulated to all of the cities with a population of 100,000, and to all cities or jurisdictions with refinery experience show this great diversity. The returns showed that there were no set format or permitting requirements. There are no sets of rules established by each state for such occurrences as a potential siting of a refinery project. In specific, there is no way of clearly identifying permit requirements for local governments. The spotty sets of permits is usually a series of adjustments to existing local laws and not a plan or united format. Examples of city permit information returned with the survey forms are included in Appendix M.

There are two alternatives for both the private sector and the local executive to use in looking at permitting requirements. First, the key is for them to make use of the detail requirements of both the federal permits and the state permits. They can get detail guidelines from those two very specific areas. Second, the workbook has established as much detail as possible in a sample of each area so that the local chief executive or private sector developer will have a sample of local governments to contact who may have local similarities.

The workbook has several tables which should be any easy reference form. Each table has taken samples of details returned by individual communities. All of the sample permits have been listed under the same breakdown as the state and federal permits, namely:

- Water Permits
- Air Permits
- Health and Safety Permits
- Land Use Permits
- Miscellaneous

In order to make it as easy as possible to identify those cities from the samples which might apply to a specific location, the workbook has divided the responsed into categories. The following categories will provide ready reference to anyone trying to identify similar applications or experiences as their cities under consideration.

- Strong Mayor
- Weak Mayor - Strong Council

- City Manager
- Refinery Experience
- Zoning Change Requirements
- Requires Council Approval
- Requires Public Hearing
- Requires Planning Approval

The city permit tables[104-108] also list the responsible local office and reference person for individual contact. The workbook has included in the Appendix revelent samples of sophisticated permits that have been provided with the survey response.

The user of the tables should identify their particular form of government from the columns and then note the various permits that have been required by local jurisdictions with similar circumstances. They should then contact the person identified and attempt to obtain any details or experience which should prove valuable.

All of the samples listed are directly related to a potential problem that a local community will deal with in the siting of a refinery. No attempt has been made to deal with all local ordinances and city charters that have been established since the beginning of local jurisdictions. Those would be much too many and of little help in an overview of local permits.

TABLE 54

ALABAMA STATE PERMITS

Governor James Fob, Jr.
Executive Department
Montgomery, Alabama 36130

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Alabama Water Improvement Commission NPDES	Water Permits	James W. Warr Chief Adm. Officer State Office Bldg. Montgomery, AL 36130 (205) 832-3370
Air	Alabama Air Pollution Commission PSD	Air Permits	James W. Cooper, Dir. 645 S. McDonough St. Montgomery, AL 36104 (205) 832-6770
Health & Safety	Alabama Dept. of Public Health	Health & Safety Permits	Dr. Ira L. Myers State Health Officer State Office Bldg. Montgomery, AL 36130 (205) 832-3113
Land		N/A	

TABLE 55

ALASKA STATE PERMITS

Governor Jay Hammond
Pouch A
State Capitol
Juneau, Alaska 99811

Permit	Issuing Agency	Type of Application	Responsible Person
	Dept. of Environmental Conservation (DEC)		Ernst W. Mueller, Comm Pouch O Juneau, AK 99801 (907) 465-2600
Water	DEC, Div. of Environmental Quality Mgt. (DEQM) Water Quality Section	Wastewater Discharge	Bob Martin, Chief Pouch O Juneau, AK 99801 (907) 465-2600
	Dept. of Natural Resources (DNR) Div. of Forest, Land & Water Mgt. (DFLWM), Water Section	Water Use	Brent Petrie, Chief 323 E. 4th Ave. Anchorage, AK 99501 (907) 279-5577
Air	DEC, DEQM, Air & Solid Waste Mgt. Section	Air Quality	Tom Hanna, Chief Pouch O Juneau, AK 99801 (907) 465-2666
Health & Safety	Dept. of Labor	OSHA	E. Orbeck, Comm. Dept. of Labor P. O. Box 1149 Juneau, AK 99801 (907) 465-2700
Land	N/A		
Misc.	N/A		

see following page

REFINERY SITING PERMITTING PROCESS

Alaska Statute 46-35 requires the DEC to establish a "one-sto shopping" process for environmental permits for industrial siting. a pre-application conference may be hosted by the DEC for applican and a master application (essentially a request for permit process shall be filed, so that the applicant will be advised as to all th necessary permits and application procedures.

Contact: Wood Angst, Permit Coordinator
Div. of Environmental Quality Management
Dept. of Environmental Conservation
Pouch O
Juneau, AK 99801
(907) 465-2670

TABLE 56

ARIZONA STATE PERMITS

Governor Bruce E. Babbitt
Capitol West Wing
9th Floor
Phoenix, Arizona 85007

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Bureau of Water Quality Control	Water Quality	Dr. Ronald Miller, C[illegible] Bureau of Water Qual[illegible] Control 1740 West Adams St. Phoenix, AZ 85007
	Bureau of Sanitation	Industrial Waste	John H. Beck, Chief Bureau of Sanitation 1740 West Adams St. Phoenix, AZ 85007 (602) 255-1156
Air	Arizona Dept. of Health, Bureau of Air Quality Control, Engineering Services Section	Installation Permit (Requires EIS)	Carl H. Billings, Mg[illegible] 1740 W. Adams St. Phoenix, AZ 85007 (602) 255-1144
Health & Safety	Arizona Dept. of Health, Bureau of Water Quality Control, Technical Review Section	Construction Approval (Submit Facility Plans) Operation Approval (State Regional Office Inspection)	Lyndon Hammon 1740 W. Adams St. Phoenix, AZ 85007 (602) 255-1175

WATER USE (APPROPRIATION) PERMITTING

Arizona is currently revising its water supply use regulations

For information, contact: State Water Commission
222 N. Central
Phoenix, AZ 85007
(602) 255-1550

TABLE 57

ARKANSAS STATE PERMITS

Governor Bill Clinton
250 State Capitol Building
Little Rock, Arkansas 72201

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Pollution Control & Ecology	Water Permits	Jarrell E. Southall Director 8001 National Dr. P. O. Box 9583 Little Rock, Ark. 72219 (501) 371-1701
Air	Dept. of Pollution Control & Ecology	Air Permits	Jarrell E. Southall Director 8001 National Dr. P. O. Box 9583 Little Rock, AR 72219 (501) 371-1701
Health & Safety	Dept. of Health		Dr. Robert Young Director 4815 W. Markham St. Little Rock, AR 72205 (501) 661-2000
	Dept. of Labor		Director Capitol Hill Bldg. Little Rock, AR 72201 (501) 371-1401

TABLE 58

CALIFORNIA STATE PERMITS

Governor Edmund G. Brown, Jr.
State Capitol
Sacramento, California 95814

Permit	Issuing Agency	Type of Application	Responsible Person
	The Resources Agency		Huey Johnson Sec. for Resources 1416 Ninth St. Sacramento, CA 95814 (916) 445-5656
Water	State Water Resources Control ((SWRCB), Div. of Water Rights	Permit for Diversion & Use of Water (Surface Water)	Walt Pettit, Chief P. O. Box 100 Sacramento, CA 95801 (916) 920-6301
	SWRCB NPDES	Water Quality (NPDES Permits are directly issued by the 9 Regional Offices.)	Clint Whitney, Ex. Dir P. O. Box 100 Sacramento, CA 95801 (916) 445-3085
Air	Air Resources Board	Air Quality	Tom Quinn, Chrm. 1102 Q St. Sacramento, CA 95814 (916) 322-5840
Health & Safety	Dept. of Labor	OSHA	Donald Vial, Dir. Dept. of Industrial Relations 455 Golden Gate Ave. San Francisco, CA 94102 (415) 557-3356

TABLE 59

COLORADO STATE PERMITS

Governor Richard D. Lamm
Room 136
State Captiol
Denver, Colorado 80203

Permit	Issuing Agency	Type of Application	Responsible Person
	Dept. of Health (DE) Office of Health Protection (OHP)		Robert Arnott Asst. Dir. 4210 E. 11th Ave. Denver, CO 80220 (303) 320-8333 X6354
Water	DE, OHP, Water Quality Control Div. Permits Section NPDES	Water Use (Appropriation)	Arden Wallum Acting Section Chief 4210 E. 11th Ave. Denver, CO 80220 (303) 320-8333
Air	DE, OHP, Air Pollution Control Div., Stationary Sources Section	Air Quality	A. C. Bishard, P.E. Section Chief 4210 E. 11th Ave. Denver, CO 80220 (303) 320-8333 X4136

TABLE 60

CONNECTICUT STATE PERMITS

Governor Ella T. Grasso
State of Connecticut
Executive Chambers
Hartford, Connecticut 06115

Permit	Issuing Agency	Type of Application	Responsible Person
	Dept. of Environmental Protection (DEP)		Stanley J. Pac, Dir. State Office Bldg. 165 Capitol Ave. Hartford, CT 06115 (203) 566-2110
Water	DEP, Water Compliance Unit	Water Quality	Robert E. Moore, Dir. 122 Washington St. Hartford, Ct 06115 (203) 566-3245
	CT Dept. of Health, Water Supply Section	Water Supply	Richard S. Woodhull Chief 79 Elm St. Hartford, CT 06115 (203) 566-3130
	DEP, Water Compliance Unit	Industrial Waste	Merwin E. Hupfer 122 Washington St. Hartford, CT 06115 (203) 566-5599
Air	DEP, Air Compliance Unit	Air Quality	Leonard Bruckman, Dir 165 Capitol Ave. Hartford, CT 06115 (203) 566-4030
Health & Safety	Dept. of Labor	OSHA	Department of Labor 555 Main St. Hartford, CT 06103 (203) 244-2294

DELAWARE STATE PERMITS

Governor Pierre S. duPont IV
Legislative Hall
Dover, Delaware 19001

Permit	Issuing Agency	Type of Application	Responsible Person
	Dept. of Natural Resources and Environmental Control (DNREC)		Austin P. Olney, Sec. Tatnail Bldg. Dover, DE 19901 (302) 678-4403
Water	DNREC, Div. of Environmental Control NPDES	Water Quality	Tom Eichler Tatnail Bldg. P. O. Box 1401 Dover, De 19901 (302) 678-4765
	Dept. of Health and Social Services, Div. of Pub. Health Bureau of Environmental Health	Water Supply	Donald K. Harmeson Chief Jesse S. Cooper Bldg. Capitol Square Dover, DE 19901 (302) 678-4731
Air	DNREC, Div. of Environmental Control, Air Resources Sect.	Air Quality	Robert R. French, Mgr. P. O. Box 1401 Dover, DE 19901 (302) 678-4791
Health & Safety	N/A		

FLORIDA STATE PERMITS

Governor Robert Graham
The Capitol
Tallahassee 32304

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Environmental Regulation	Water Quality	Jacob D. Varn, Sec. Twin Towers Bldg. 2600 Blair Stone Rd. Tallahassee, FL 323((904) 488-4807
Air	Dept. of Environmental Regulation	Air Quality	Jacob D. Varn, Sec. Twin Towers bldg. 2600 Blair Stone Rd. Tallahassee, FL 3230 (904) 488-4807
Health & Safety	Dept. of Labor	OSHA	Dept. of Labor Art Museum Plaza Suite 4 2809 Art Museum Dr. Jacksonville, FL 322 (904) 791-2895

GEORGIA STATE PERMITS

Governor George Busbee
State Capitol
Atlanta, Georgia 30334

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Georgia Dept. of Natural Resources Environmental Protection Division NPDES	Water Permits	J. Leonard Ledbetter Director 270 Washington St. S.W Atlanta, GA 30334 (404) 656-4713
Air	Georgia Dept. of Natural Resources, Environmantal Protection Division PSD	Air Permits	J. Leonard Ledbetter director 270 Washington St. S.W Atlanta, GA 30334 (404) 656-4713
Health & Safety	Dept. of Labor	OSHA	Dept. of Labor 152 New St. Macon, GA 31201 (912) 746-5143
Land	N/A		
Misc.	N/A		

A.N.I.: REFINERY SITING REQUEST PROCESS

Department of Industry and Trade would coordinate the proposal with the Environmental Protection Division. The Environmental Protection Division has been delegated the Federal Environmental permitting agency (PSD, NPDES) and would process air and water permit applications.

TABLE 64

HAWAII STATE PERMITS

Governor George R. Aryoshi
Executive Chambers
State Capitol
Honolulu, Hawaii 96813

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Hawaii State Dept. of Health, Environmental Health Division	Water Permits	George Yuen Director of Health 1250 Punch Bowl St. Honolulu, HI 96800 (808) 548-6505
	NPDES		
Air	Hawaii State Dept. of Health, Environmental Health Division	Air Permits	George Yuen Director of Health 1250 Punch Bowl St. Honolulu, HI 96800 (808) 548-6505
Health & Safety	Hawaii State Dept. of Labor	OSHA	Wayne Mount, Director 835 Mililani St. Honolulu, HI 96800 (808) 548-7510
Land	N/A		
Misc.	Hawaii State Dept. of Planning & Economic Development		Hideto Kono, Director 250 South King St. Honolulu, HI 96800 (808) 548-6914

TABLE 65

IDAHO STATE PERMITS

Governor John V. Evans
State House
Boise, Idaho 83720

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Idaho Dept. of Health and Welfare, Environmental Services Division, Water Quality Bureau	Water Quality	Al E. Murray, Chief 4th & State Boise, ID 83720 (208) 384-2433
Air	Idaho Dept. of Health and Welfare	Air Quality	Michael Murray Director 4th & State Boise, ID 83720 (208) 384-2433
Health & Safety	Dept. of Labor	OSHA	Dept. of Labor 1315 W. Idaho St. Boise, ID 83706 (208) 284-1867
Land	N/A		

TABLE 66

ILLINOIS STATE PERMITS

Governor James R. Thompson
State House
Springfield, Illinois 62706

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Illinois Environmental Protection Agency, Division of Water Pollution Control NPDES	Water Quality	Roger Kanerva, Mgr. 2200 Churchill Rd. Springfield, IL 62706 (217)
Air	Illinois Environmental Protection Agency, Division of Air Pollution Control	Air Quality	Dan Goodwin, Mgr. 2200 Churchill Rd. Springfield, IL 62706 (217) 782-7326
Health & Safety	Dept. of Labor	OSHA	Dept. of Labor 344 Smoke Tree Busine Park Aurora, IL 60542 (312)896-8700

TABLE 6/

INDIANA STATE PERMITS

Governor Otis R. Bowen
Room 206
State House
Indianapolis, Indiana 46204

Permit	Issuing Agency	Type of Application	Responsible Person
	State Board of Health (SBH)		R. G. Blankenbaker, MD State Health Comm. 1330 W. Michigan St. Indianapolis, IN 46206 (317) 633-8400
Water	Stream Pollution Control Board (SPCB) NPDES	Wastewater Discharge	Oral Hert, Tech. Sec. 1330 W. Michigan St. Indianapolis, IN 46206 (317) 633-0167
	Dept. of Natural Resources (DNR) Div. of Water (DV)	Water Withdrawal from Navigable Waters	Victor Wenning, Asst. Chief Room 605 State Office Bldg. Indianapolis, IN 46204 (317) 232-4160
Air	SBH, Div. of Air Pollution Control	Air Quality	Harry D. Williams, Dir 1330 W. Michigan St. Indianapolis, IN 46206 (317) 633-0600
Health & Safety	Dept. of Labor	OSHA	William Lanam, Comm. Indiana Div. of Labor 1013 State Office Bldg Indianapolis, IN 46204 (317) 633-4473
Land	DNR, DW	Floodway Permit (Flood Plains Construction)	Victor Wenning, Asst. Chief Room 605 State Office bldg. Indianapolis, IN 4620[illegible] (317) 232-4160

IOWA STATE PERMITS

Governor Robert D. Ray
State Captiol
Des Moines, Iowa 50319

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Environmental Quality NPDES	Water Quality	Larry E. Crane Executive Director Henry A. Wallace Bldg. 900 E. Grand Des Moines, IA 50319 (515) 281-8854
Air	Dept. of Environmental Quality	Air Quality	Larry E. Crane Executive Director Henry A. Wallace Bldg. 900 E. Grand Des Moines, IA 50319 (515) 281-8854
Health & Safety	Bureau of Labor	OSHA	Allen J. Meier Bureau of Labor 307 E. 7th Des Moines, IA 50319 (515) 281-3606
Land	Iowa State Commerce Commission	Pipeline	John Hensel Executive Secretary 300 4th St. Des Moines, IA 50319 (515) 281-3606
Misc.	Natural Resources Council	Water Withdrawal Flood Plain Activity	James Webb Henry A. Wallace Bldg. 900 E. Grand Des Moines, IA 50319 (515) 281-5572

TABLE 69

KANSAS STATE PERMITS

Governor John W. Carlin
2nd Floor
State Captiol
Topeka, Kansas 66612

Permit	Issuing Agency	Type of Application	Responsible Person
	Dept. of Health and Environment (DHE), Division of Environment (DE)		Melville W. Gray, Dir. 6700 S. Topeka Ave. Topeka, KS 66620 (913) 862-9360
Water	DHE, DE, Bureau of Water Quality	Water Quality	Eugene Jensen, Dir. 6700 S. Topeka Ave. Topeka, KS 66620 (913) 862-9360 X228
	NPDES		
	DHE, DE, Bureau of Public Water Supply	Water Supply	N. Jack Burris 6700 S. Topeka Ave. Topeka, KS 66620 (913) 862-9360 X218
Air	DHE, DE, Bureau of Air Qualitry and Occupational Health	Air Quality	Howard F. Saiger, Dir. 6700 S. Topeka Ave. Topeka, KS 66620 (913) 661-9360 X266
Health & Safety	Dept. of Labor	OSHA	Dept. of Labor 216 N. Waco Suite B Wichita, KS 67202 (316) 267-6311 X644

TABLE 70

KENTUCKY STATE PERMITS

Governor Julian Carroll
State Capitol
Frankfort, Kentucky 40601

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. for Natural Resources and Environmental Protection, Div. of Water Quality	Water Quality	Dr. Robert E. Blanz Director Century Plaza U. S. 127S Frankfort, KY 40601 (502) 564-3410
Air	Dept. for Natural Resources and Environmental Protection, Div. of Air Pollution Control PSD	Air Quality	Norman Schell, Dir. West Frankfort Office Complex U. S. 127S Frankfort, KY 40601 (502) 564-3382
Health & Safety	Dept. of Labor	OSHA	James R. Yocom, Comm. Dept. of Labor U. S. Highway 127 S Frankfort, KY 40601 (502) 564-3070
Land	N/A (Kentucky Area Development Districts have jurisdiction)		
Misc.	N/A		

Contact Department of Commerce which will coordinate meetings with agencies from which applicant must receive permits.

TABLE 71

LOUISIANA STATE PERMITS

Governor David Treen
P. O. Box 44004
Baton Rouge, Louisiana 70804

Permit	Issuing Agency	Type of Application	Responsible Person
	Dept. of Natural Resources (DNR) Office of Environmental Affairs (OEA)		Jim Porter Asst. Sec. for Environmental Affairs P. O. Box 44066 Baton Rouge, LA 70804 (504) 925-6580

In January 1980, Louisiana began major reorganization of the environmental permit process, passing authority from the Dept. of Health and Human Resources to the DNR, which is now the sole issuing agency for environmental permits. As of this date, of this report, information on specific offices and contact personnel for various permits within the OEA is unavailable. Contact Jim Porter (above) for current status information.

TABLE 72

MAINE STATE PERMITS

Governor Joseph E. Brennan
State Capitol
Augusta, Maine 04880

Permit	Issuing Agency	Type of Application	Responsible Person
	Dept. of Environmental Protection (DEP)		Henry E. Warren, Comm. State House Augusta, ME 04330 (207) 289-2811
Water	DEP, Bureau of Water Quality Control	Water Quality	Stephen Groves, Dir. State House Augusta, ME 04330 (207) 289-2591
	ME Dept. of Human Services (MDHS) Div. of Environmental Health	Water Supply	Donald C. Hoxie, Dir. State House Augusta, ME 04330 (207) 289-0433
	DEP, Div. of Industrial Services NPDES	Industrial Waste	Charles King, Chief State House Augusta, ME 04330 (207) 289-2591
Air	DEP, Bureau of Air Quality Control PSD	Air Quality	David E. Tudor, Chief State House Augusta, ME 04330 (207) 289-3826
Health & Safety	MDHS, Division of Health Engineering	Noise Control	Donald C. Hoxie, Dir. State House Augusta, ME 04330 (207) 289-0433
Land	DEP, Land Quality Control	Land use (Whole state)	Director Station No. 17 State House August, ME 04433 (207) 289-2811

Permit	Issuing Agency	Type of Application	Responsible Person
Land	Dept. of Conservation, Land Use Regulation Comm.	Land Use (In any unorganized territory)	Michael Barrett State No. 22 State House Augusta, ME 04330 (207) 289-2811
Misc.	N/A		

TABLE 73

MARYLAND STATE PERMITS

Governor Harry R. Hughes
Executive Department
State House
Annapolis, Maryland 21404

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Natural Resources, Water Resources Admin.	Industrial Waste	Thomas C. Andrews Dir. 580 Taylor Ave. Tawes State Office Bld Annapolis, MD 21401 (301) 269-3846
	NPDES		
	Dept. of Health and Mental Hygiene Div. of Water Supply, Water and Sewage Program	Water Supply	Raymond Anderson, Chie 201 W. Preston St. Baltimore, MD 21201 (301) 383-4249
Air	DHMH, Air Quality	Permit to Construct	George P. Ferreri, Adm 201 W. Preston St. Baltimore, MD 21201 (201) 383-2779
Health & Safety	Dept. of Labor	OSHA	Harvey A. Epstein, Com Dept. of Licensing & Regulation Div. of Labor and Ind. 203 E. Baltimore St. Baltimore, MD 21202 (301) 383-2251

There is no "umbrella" organization for environmental regulation in Maryland.
Maryland is approaching EPA PSD approval.

TABLE 74

MASSACHUSETTS STATE PERMITS

Governor Edward J. King
Room 360
State House
Boston, Massachusetts 02133

Permit	Issuing Agency	Type of Application	Responsible Person
	Executive Office of Environmental Affairs (EOEA)		John A. Bewick, Dir. 100 Cambridge St. Boston, MA 02202 (617) 727-9800
Water	EOEA, MA Dept. of Environmental Quality (MDEQE), Div. of Water Pollution Control (DWPC)	Water Quality	Thomas C. McMahon Director 110 Tremont St. Boston, MA 02108 (617) 727-3855
	EOEA, MDEQE, Div. of Water Supply	Water Supply	Bob McCracken Acting Director 600 Washington St. Boston, MA 02111 (617) 727-2092
	EOEA, MDEQE, DWPC	Industrial Waste	Glen Gilmore 110 Tremont St. Boston, MA 02108 (617) 727-3855
Air	EOEA, MDEQE, Div. of Air Quality Control	Air Quality	Kenneth Haag, Dir. 600 Washington St. Boston, MA 02111 (617) 727-2658
Health & Safety	Dept. of Public Health, Div. of Environmental Health	Noise Control	Elise Comproni, Assoc. Air Pollution Control Engineer 600 Washington St. Boston, MA 02111 (617) 727-4782

TABLE 75

MICHIGAN STATE PERMITS

Governor William G. Milliken
State Capitol
Box 30013
Lansing 48909

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Natural Resources, Water Quality Division NPDES	Water Quality	Chief Dept. of Natural Resources, Water Quality Division Lansing, MI 48926
Air	Dept. of Natural Resources, Air Quality Division	Site Approval Permit to Install Permit to Operate	Delbert Rector, Chief Dept. of Natual Resources, Air Quality Division Lansing, MI 48926 (517) 322-1330
Health & Safety	Dept. of Public Health	OSHA	Dr. Maurice Reizen Director Dept. of Public Health Lansing, MI 48926 (517) 373-1320
	Dept. of Labor	OSHA	Director Dept. of Labor Lansing, MI 48926
Land	N/A		
Misc.	Michigan Environmental Review Board	Environmental Assessment/EIS Review	Dr. William E. Cooper Chairman Dept. of Zoology Michigan State Univ. East Lansing, MI 4882[illegible] (517) 353-2262

TABLE 75

MICHIGAN CONTINUED

REFINERY SITING REQUEST PROCESS

Both the Department of Commerce and the Department of Natural Resources serve as a contact and coordinative points for industry.

Several permits, licenses, and approvals needed primarily from the Department of Natural Resources ("LEAD AGENCY")

Meeting held to explain permitting process and application forms. Environmental Assessment and/or EIS may be sent to the Michigan Environmental Review Board.

TABLE 76

MINNESOTA STATE PERMITS

Governor Albert H. Quie
State Capitol
St. Paul, Minnesota 55155

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Minnesota Pollution Control Agency NPDES	Liquid Storage Facility State Disposal System	Terry M. Hoffman Director 1935 W. County Rd.B-2 Roseville, MN 55113 (612) 296-73001
	Minnesota Dept. of Natural Resources	Work in Public Waters Water Appropriation	Joseph N. Alexander Director 658 Cedar St. St. Paul, MN 55155 (612) 296-2549
Air	Minnesota Pollution Control Agency	Installation Permit Operating Permit	Terry M. Hoffman Director 1935 W. County Rd. B-2 Roseville, MN 55113 (612) 296-7301
Health & Safety	Minnesota Dept. of Health	Plumbing Plan Review	George R. Patterson Director 717 Delaware St. S. E. Minneapolis, MN 55440 (612) 296-5460
Land	Minnesota Dept. of Natural Resources	Utility crossings of public lands and waters	Joseph N. Alexander Director 658 Cedar St. St. Paul, MN 55155 (612) 296-2549

Permit	Issuing Agency	Type of Application	Responsible Person
Misc.	Minnesota Environmental Quality Board	EIS Approval	Arthur E. Sidner Director 550 Cedar St. St. Paul, MN 55101 (612) 296-6662

REFINERY SITING REQUEST PROCESS

1. Certificate of need acquired from Minnesota Energy Agency.
2. EIS prepared by Minnesota Pollution Control Agency.
3. EIS approved by Minnesota Environmental Quality Board.
4. Necessary permits obtained from specified agencies.

TABLE 77

MISSISSIPPI STATE PERMITS

Governor Cliff Finch
The Capitol
Jackson, Mississippi 39205

Permit	Issuing Agency	Type of Application	Responsible Person
	Mississippi Air & Water Pollution Control Commission (MAWPCC)		Charles H. Chisholm Executive Director P. O. Box 10385 Jackson, MS 39209 (601) 961-5171
Water	MAWPCC, Water Division, Industrial Waste Water Section NPDES	Water Quality	Bill Barnett Coordinator P. O. Box 10385 Jackson, MS 39209 (601) 961-5171
	State Board of Health	Water Supply	James C. McDonald Director P. O. Box 1700 Jackson, MS 39205 (601) 354-6616
Air	MAWPCC Division of Air Pollution Control	Air Quality	Dwight Wiley, Chief P. O. Box 10385 Jackson, MS 39209 (601) 961-5171
Health & Safety	Dept. of Labor	OSHA	Department of Labor 5760 1-55 North Frontage Road East Jackson, MS 39211 (601) 969-4606

TABLE 78

MISSOURI STATE PERMITS

Governor Joseph P. Teasdale
Executive Office
State Capitol Building
Jefferson City, Missouri 65101

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Natural Resources, Div. of Environmental Quality, Water Control Program NPDES	Water Quality	Richard F. Rankin Director P. O. Box 1368 Jefferson City, MO 65102 (314) 751-3241
Air	Dept. of Natural Resources, Div. of Environmental quality, Air Pollution Control Program	Air Quality	Robert J. Schreiber, J Staff Director P. O. Box 1368 Jefferson City, MO 65102 (314) 751-3241
Health & Safety	Dept. of Labor	OSHA	Department of Labor 1150 Grand Ave. 6th Fl 12 Grand Ave. Kansas City, MO 64106 (816) 374-2756
Land	N/A		

REFINERY SITING REQUEST PROCESS

A preliminary report outlining processes and waste discharge (air, water, solid and hazardous wastes) should be submitted to: Division of Environmental Quality, Department of Natural Resources, 2010 Missouri Blvd., P. O. Box 1368, Jefferson City, MO 65102

Following staff review of the concept, specific and detailed applications for permits would have to be made as noted above, all environmental programs within the Missouri Department of Natural Resources.

TABLE 79

MONTANA STATE PERMITS

Governor Thomas L. Judge
State Capitol
Helena, Montana 59601

Permit	Issuing Agency	Type of Application	Responsible Person
	Dept. of Health and Environmental Sciences (DHES) Environmental Sciences Division (ESD)		Donald G. Willems Administrator Cogswell Bldg. Helena, MT 59601 (406) 449-2544
Water	DHES, ESD, Water Quality Bureau (WQB)	Water Quality	Steve Pilcher, Chief Cogswell Bldg. Helena, MT 59601 (406) 449-2406
	DHES, ESD, WQB Potable Water Supply	Water Supply	Arthur Clarkson, Chief Cogswell Bldg. Helena, MT 59601 (406) 449-2406
Air	DHES, ESD, Air Quality Bureau	Air Quality	Michael Roach, Chief Cogswell Bldg. Helena, MT 59601 (406) 449-3454
Health & Safety	Dept. of Labor	OSHA	Department of Labor Petroleum Bldg. Suite 525 2812 1st Ave. North Billings, MT 59101
Land	N/A		

Permit	Issuing Agency	Type of Application	Responsible Person
Misc.	Montana Dept. of Natural Resources and Conservation (MDNRC) Facility Siting Division	(Major facility siting) Certificate of Need Certificate of Environmental Compatibiity	Randall Moy Administrator 32 South Ewing Helena, MT 59601 (406) 449-4600

The MDNRC Facility Siting Division is currently operating under interim regulations following reorganizational legislation. New regulations are presently being promulgated.

TABLE 80

NEBRASKA STATE PERMITS

Governor Charles Thone
State Captiol
Lincoln, Nebraska 68509

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Environmental Control	Water Quality	Bob Wall, Chief Water Pollution Contro P. O. Box 94877 State House Station Lincoln, NE 68509 (402) 471-2186
	Dept. of Health	Water Supply	Clifford L. Summers, Director Div. of Environmtl. Eng P. O. Box 94877 State House Station Lincoln, NE 68509 (402) 471-2674
	Dept. of Environmental Water Pollution Control NPDES	Industrial Waste	Jay Ringenberg Permits and Enforcemen P. O. Box 94877 State House Station Lincoln, NE 68509 (402) 471-2186
Air	Dept. of Environmental Control	Air Quality	Gene Robinson, Chief Div. of Air Pollution Control P. O. Box 94877 State House Station Lincoln, NE 68509 (402) 471-2186
Health & Safety	Dept. of Labor	OSHA	Dept. of Labor Overland-Wolf Bldg. Room 100 6910 Pacific St. Omaha, NE 68106 (402) 221-9341

TABLE 81

NEVADA STATE PERMITS

Governor Robert F. List
Governor's Mansion
Carson City, Nevada 89701

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Conservation and Natural Resources, Division of Water Resources NPDES	Water Quality	William J. Newman 201 S. Fall St. Carson City, NV 89710 (702) 885-4380
Air	Dept. of Conservation and Natural Resources, Division of Environmental Protection	Air Quality	Ernest Gregory Administrator 201 S. Fall St. Carson City, NV 89710 (702) 885-4670
Health & Safety	Dept. of Human Resources, Bureau of Consumer Health Protection Services		James Edmundson 505 E. King St. Carson City, NV 89710 (702) 885-4750
Land	Land Use Planning		Jac R. Shaw 201 S. Fall St. Carson City, NV 89710 (702) 885-4360
Misc.	Industrial Commission Occupational Safety and Health		Ralph Langley 515 E. Musser Carson City, NV 89710 (702) 885-5240

REFINERY SITING REQUEST PROCESS

Request would be directed to State Planning Coordinator's Office which would circulate it to affected state agencies for review and comment. Further action would depend on said comments. Planning Coordinator would probably request information briefing.

TABLE 82

NEW HAMPSHIRE STATE PERMITS

Governor Hugh Gallen
State House
Concord, New Hampshire 03301

Permit	Issuing Agency	Type of Application	Responsible Person
Water	NH Water Supply & Pollution Control Comm. (NHWSPCC)	Water Quality	William A. Healy, Executive Director 105 Loudon Rd. P. O. Box 95 Concord, NH 03301 (603) 271-3503
	NHWSPCC	Water Supply	Stephen Leavenworth, P. Assoc. San. Engr. 105 Loudon Rd. P. O. Box 95 Concord, NH 03301 (603) 271-3139
	NHWSPCC	Industrial Waste	Russell Nylander, P.E. Senior San. Engr. 105 Loudon Rd. P. O. Box 95 concord, NH 03301 (603) 271-3503
Air	Dept. of Health and Welfare	Air Quality	Dennis Lunderville Director Air Pollution Control State Laboratory Bldg. Hazen Dr. Concord, NH 03301 (603) 271-2281
Health & Safety	Dept. of Health and Welfare	OSHA	Max Helgemeier Occupational Health Services State Laboratory Bldg. Hazen Dr. Concord, NH 03301 (603) 271-2281

TABLE 83

NEW JERSEY STATE PERMITS

Governor Brendan T. Byrne
State Capitol
Trenton, New Jersey 08625

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Environmental Protection	Water Quality	Jeff Zelikson, Deputy Director Div. of Water Resource: 1474 Propsect St. Trenton, NJ 08625 (609) 292-1637
	Dept. of Environmental Protection	Industrial Waste	Douglas M. Clark, Asst Director Water Planning & Mgt. Element 1474 Propspect St. Trenton, NJ 08625
Air	Dept. of Environmental Protection	Air Quality	Herbert Wortreich, Chie Bureau of Air Pollution Control P. O. Box 1390 Trenton, NJ 08625 (609) 292-6704
Health & Safety	Dept. of Labor	OSHA	Department of Labor 2101 Ferry Ave. Room 4 Camden, NJ 08104 (609) 757-5181

~~TABLE 84~~

NEW MEXICO STATE PERMITS

Governor Bruce King
Executive Legislative Building
Santa Fe
New Mexico 87503

Permit	Issuing Agency	Type of Application	Responsible Person
	Health and Environment Dept., Environmental Improvement Div.		Thomas E. Baca Director P. O. Box 968 Santa Fe, NM 87503 (505) 827-5271
Water	Energy and Minerals	Ground Water Discharge Permit	Joe D. Ramey, Director P. O. Box 2088 Santa Fe, NM 87501 (505) 827-3260
	Natural Resources Dept. Water Resources Div., Water Rights Bureau	Permit to Appropriate	Gene Gray, Chief Room 101 Bataan Memorial Bldg. Santa Fe, NM 87503 (505)
Air	Health and Environment Dept. Environmental Improvement Division, Air Quality Bureau	Air Quality Construction Permit	Kenneth M. Hargis, Chief P. O. Box 968 Santa Fe, NM 87503 (505) 827-5271
Health & Safety	Health and Environment Dept. Environ=mental Improvement Division		Thomas E. Baca Director P. O. Box 968 Santa Fe, NM
Land	Land Office	Facilities on State-owned Lands	Alex Armijo, Comm. 310 Old Santa Fe Trail Sante Fe, NM 87503 (505) 827-2881
Misc.	N/A		

TABLE 85

NEW YORK STATE PERMITS

Governor Hugh L. Carey
Executive Chamber
State Captiol
Albany, New York 12224

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Environmental Conservation	Water Quality	Eugene Seebald, Dir. Div. of Pure Waters 50 Wolf Rd. Albany, NY 12233 (518) 457-6674
	Dept. of Environmental Conservation NPDES	Industrial Waste	Salvatore Pagano Director Bureau of Industrial Programs 50 Wolf Rd. Albany, NY 12233 (518) 457-3967
Air	Dept. of Environmental Conservation	Air Quality	Harry Hovey Div. of Air Resources 50 Wolf Rd. Albany, NY 12233 (518) 457-7231
Health & Safety	Dept. of Labor	OSHA	Dept. of Labor O'Brien Federal Bldg. Clinton Ave. & Pearl Room 132 Albany, NY 12207 (518) 472-6085
Land	Dept. of Environmental Conservation	Wetlands Use	Tim Cook Div. Reg. Affairs 50 Wolf Rd. Albany, NY 12233 (518) 457-7418

New York is approaching US EPA PSD approval.

TABLE 80

NORTH CAROLINA STATE PERMITS

Governor James B. Hunt, Jr.
The Capitol
Raleigh, North Carolina 27602

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Natural Resources and Community Development, Div. of Environmental Mgt.	Permit to Construct Wastewater Treatment Facilities, Sewer System Extensions, and Sewer Systems not discharging into surface waters	A. C. Turnage P. O. Box 27687 Raleigh, NC 27611 (919) 733-7120
	NPDES	Authorization to Construct Wastewater Treatment and Handling Facilities (Surface waters)	
		Water Use Permit	
		Well Construction Permit	
		401 Water Quality Certification	
Air	Dept. of Natural Resources and Community Development, Div. of Environmental Mgt.	Permit to Construct and Operate Air Pollution Abatement Facilities and/or Emission Sources	A. C. Turnage P. O. Box 27897 Raleigh, NC 27611
	PSD		

TABLE 36

NORTH CAROLINA Continued

Permit	Issuing Agency	Application	Responsible Person
Health & Safety	Department of Labor	OSHA	John C. Brooks, Comm. NC Dept. of Labor P. O. Box 27407 11 W. Edenton St. Raleigh, NC 27611
	Dept. of Human Resources		Hugh Tilson Albemarle Bldg. Raleigh, NC 27611 (919) 733-3446
Land	Dept. of Natural Resources and Community Development, Office	CAMA Permit for Major Development (Coastal zone)	Ken Stewart, Director P. O. Box 27687 Raleigh, NC 27611 (919) 733-2293
Misc.	Dept. of Commerce		D. M. Faircloth, Dir. 430 N. Salisbury Raleigh, NC 27611 (919) 733-4962

OIL REFINING FACILITIES (SPECIAL PERMIT)

Operation and/or construction of an oil refining facility requires a permit from the Department of Natural Resources and Community Development.

REFINERY SITING PERMIT PROCESS

North Carolina is in the process of establishing an office to coordinate all environmental permitting procedures.

Contact: Anne S. Taylor, Director
Office of Regulatory Relations
P. O. Box 27687
Raleigh, NC 27611
(919) 733-6376

TABLE 87

NORTH DAKOTA STATE PERMITS

Governor Arthur A. Link
State Capitol Building
Bismarck, North Dakota 58505

Permit	Issuing Agency	Type of Application	Responsible Person
Water	ND Health Dept. Div. of Environmental Engineering, Environmental Control	Water Quality	Gene A. Christianson, P Chief 1200 Missouri Ave. Bismarck, ND 58505 (701) 224-2370
	ND Water Comm. NPDES	Appropriation Permit	Vernon Fahy State Engineer Missouri Office Bldg. Bismarck, ND 58505 (701) 224-2750
Air	ND Health Dept. Div. of Environmental Engineering Environmental Control	Air Quality	Gene A. Christianson, P Chief 1200 Missouri Ave. Bismarck, ND 58505 (701) 224-2370
Health & Safety	Dept. of Labor	OSHA	Dept. of Labor Russel Bldg. Highway 83 N, Rt. 1 Bismarck ND 58501 (701) 255-4011 X521

TABLE 87

~~NORTH DAKOTA~~ ~~Continued~~

Permit	Issuing Agency	Type of Application	Responsible Person
Land	ND Land Dept.		R. E. Lommen Capitol Bldg. Bismarck, ND 58505 (701) 224-2801
	ND Dept. of Agriculture		Myron Must Capitol Bldg. Bismarck, ND 58505 (701) 224-2231
	ND Soil Conservation Committee		Gary L. Puppe Capitol Bldg. Bismarck, NC 58505 (701) 224-2651
Misc.	ND Public Service Commission	Energy Conversion Facility Siting	Richard A. Elkin President Capitol Bldg. Bismarck, ND 58505 (701) 224-2400

REFINERY SITING REQUEST PROCESS

1. File letter of intent to construct one year prior to filing application.
2. File application for Certificate of Site Compatibility.
3. Notice of hearings on application for Certificate of Site Compatibility.
4. Hearing on application.
5. Order granting or denying application.

TABLE 88

OHIO STATE PERMITS

Governor James A. Rhodes
State Capitol
Columbus, Ohio 43215

Permit	Issuing Agency	Type of Application	Responsible Person
Water	OH Environmental Protection Agency	Water Quality	Ernie Rotering, Chief Div. of Water Quality Standards P. O. Box 1049 Columbus, OH 43216 (614) 466-6686
	OH Environmental Protection Agency	Water Supply	James Kneale, Chief Off. of Pub. Water Sup P. O. Box 1049 Columbus, OH 43216 (614) 466-8307
	OH Environmental Protection Agency	Industrial Waste	Andrew Turner, Asst. Cl Div. of Industrial Was Water P. O. Box 1049 Columbus, OH 43216 (614) 466-2390
	NPDES		
Air	OH Environmental Protection Agency	Air Quality	Chuck Taylor, Acting Chief Control P. O. Box 1049 Columbus, OH 43216 (614) 466-6686
Health & Safety	Dept. of Labor	OSHA	Department of Labor Federal Office Bldg. Room 634 200 N. High St. Columbus, OH 43215 (614) 469-5582

Office of Air Pollutio

TABLE 88

OHIO Continued

Permit	Issuing Agency	Type of Application	Responsible Person
Land	OH Environmental Protection Agency	Land Pollution Control	Don Day, Chief Div. of Land Pol- lution Control P. O. Box 1049 Columbus, OH 43216 (614) 466-6686

TABLE 89

OKLAHOMA STATE PERMITS

Governor George P. Nigh
212 State Capitol Building
Oklahoma City, Oklahoma 73105

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Pollution Control	Water Quality	David O. Dillon, Jr. Programs Director Box 53504 N.E. 10th & Stonewall Oklahoma City, OK 7315 (405) 271-4677
	Dept. of Health	Water Supply	Charles Newtown, Chief Water Quality Services N.E. 10th & Stonewall Oklahoma City, OK 7311 (405) 271-6315
	Dept. of Health	Industrial waste	James R. Barnett, Acti Executive Director Water Resources Board N.E. 10th & Stonewall Oklahoma City, OK 7310 (405) 271-2555
Air	Dept. of Health	Air Quality	John W. Gallion, Chief Air Quality Service P. O. Box 53551 Oklahoma, OK 73105 (405) 271-5220
Health & Safety	Dept. of Health	OSHA	Dale McHard, Chief Occupational RAD Healt Services
		Noise	N.E. 10th & Stonewall Oklahoma, OK 73105 (405) 271-5221

TABLE 90

OREGON STATE PERMITS

Governor Victor G. Atiyeh
207 State Capitol
Salem, Oregon 97310

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Environmental Quality		William H. Young, Director 1234 S.W. Morrison St. Portland, OR 97205 (503) 229-5278
	Dept. of Environmental Quality	Water Quality	Harold Sawyer, Adm. Water Quality Serv. 1234 S.W. 5th Ave. Portland, OR 97201 (503) 229-5324
	NPDES		
Air	Dept. of Environmental Quality	Air Quality	Jack Weathersbee, Adm. Air Quality Div. DEQ Portland, OR 97201 (503) 229-5267
Health & Safety	Dept. of Labor	OSHA	Roy G. Green, Dir. Workers Comp. Dept. Labor and Ind. Bldg. Salem, OR 97310 (503) 378-3302

TABLE 91

PENNSYLVANIA STATE PERMITS

Governor Richard L. Thornburgh
Main Capitol
Harrisburg, Pennsylvania 17120

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Environmental Resources Bureau of Water Quality Mgt. NPDES	Water Quality	Louis Berchini, Dir. P. O. Box 2063 Harrisburg, PA 17120 (717) 787-2666
Air	Dept. of Environmental Resources Bureau of Air Quality and Noise	Air Quality	James Hambright, Dir. P. O. Box 2063 Harrisburg, PA 17120 (717) 787-9702
Health & Safety	Dept. of Labor	OSHA	Dept. of Labor Progress Plaza 49 N. Progress Ave. Harrisburg, PA 17109 (717) 782-3902
Land	N/A		
Misc.	N/A		

REFINERY SITING REQUEST PROCESS

State agency coordinators would work with the requestor to review refinery needs, evaluate available industrial development sites, consult on state requirements and provide as much guidance as possible. Contacts would be made with local officials.

TABLE 92

RHODE ISLAND STATE PERMITS

Governor J. Joseph Garrahy
State House
Providence, Rhode Island 02903

Permit	Issuing Agency	Type of Application	Responsible Person
	Dept. of Environmental Mgt.		W. Edward Wood, Dir. 83 Park St. Providence, RI 20908 (401) 277-2771
Water	Dept. of Environmental Mgt.	Water Quality	James W. Feaster, Chie Health Bldg., Room 209 75 Davis St. Providence, R. I. 0290 (401) 277-2234
	Dept. of Health	Water Supply	John Hagopian Principal Sanitary Eng Health Bldg. Room 209 75 Davis St. Providence, R. I. 0290 (401) 277-2234
	Dept. of Health	Industrial Waste	John Hagopian Prin. Sanitary Enginee Health Bldg. Room 209 75 Davis St. Providence, R. I. 0290 (401) 277-2234
Air	Div. of Air Pollution Control Dept. of Environmental Mgt.	Air Quality	Thomas E. Wright, Chie Health Bldg. Room 209 75 Davis St. Providence, R. I. 0290 (401) 277-2808
Health & Safety	Div. of Occupational Health Dept. of Health	OSHA	James P. Deery, M. D. Chief Dept. of Health Health Bldg. Room 206 75 Davis St. Providence, R. I. 0290 (401) 277-2438

TABLE 93

SOUTH CAROLINA STATE PERMITS

Governor Richard W. Riley
State House, 1st Floor West Wing
Box 11450
Columbia, South Carolina

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Health and Environmental Control, Bureau of Wastewater and Stream Quality Control, Industrial and Agricultural Wastewater Div.	Permit to Construct	Robert G. Gross, Dir. 2600 Bull St. Columbia, SC 29201 (803) 758-3877
	NPDES		
	Dept. of Health and Environmental Control, Bureau of Special Environmental Programs Water Supply Div.	Permit to Construct (Water Appropriation)	R. L. Shaw, Dir. 2600 Bull St. Columbia, SC 29201 (803) 758-5544
Air	Dept. of Health and Environmental Control, Bureau of Air Quality Control	Permit to Construct Permit to Operate	William G. Crosby Chief 2600 Bull St. Columbia, SC 29201 (803) 758-5406
	PSD		
Health & Safety	Dept. of Health and Environmental Control	Environmental Health & Safety Permits	Johnnie W. Smith 2600 Bull St. Columbia, SC 29201 (803)
Land	SC Coastal Council	(If in coastal area)	Wayne Beam 1116 Banker Trust Towe Columbia, SC 29201 (803) 758-8442

Misc. N/A

REFINERY SITING REQUEST PROCESS

Contact: South Carolina Development Board
1301 Gervais St.
P. O. Box 927
Columbia, SC 29201

South Carolina Dept. of Health and Environmental Control

South Carolina Coastal Council
(If in coastal area)

TABLE 94

SOUTH DAKOTA STATE PERMITS

Governor William J. Janklow
State Capitol Building
Pierre, South Dakota 57501

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Water and Natural Resources	Permit Application	Leon Schochenmaier Dept. of Water and Natural Resources Joe Foss Bldg. Pierrre, SD 57501 (605) 773-4058
	Dept. of Water and Natural Resources	Water Quality	James D. Nelson Water Quality Control Preogram Joe Foss Bldg. Pierre, SD 57501 (605) 773-3351)
	Dept. of Water and Natural Resources	Water Supply	Mark E. Steichen, Chie Water Hygiene Program Water Quality Control Pierre, SD 57501 (605) 773-3351
	Dept. of Water and Natural Resources	Industrial Waste	William A. Aisenbrey Chief Operator Clarification Water Quality Control Joe Foss Bldg. Pierre, SD 57501 (605) 773-3351
Air	Dept. of Water and Natural Resources	Air Quality	Joel E. Smith, Chief Air Quality & Solid Waste Program Joe Foss Building Pierre, SD 57501 (605) 224-3329

SOUTH DAKOTA Continued

Permit	Issuing Agency	Type of Application	Responsible Person
Health & Safety	Dept. of Labor	OSHA	Dept. of Labor Court House Bldg. Room 408 300 North Dakota Ave. Sioux Falls, SD 57102 (605) 336-2980

TABLE 95

TENNESSEE STATE PERMITS

Governor Lamar Alexander
State Capitol Building
Nashville, Tennessee 37219

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Bureau of Environmental Health Services		Dr. Eugene W. Fowinkle Comm. for Environment Bureau of Environmenta Health Services Room 344 349 Cordell Hull Bldg. Nashville, TN 37219 (615) 741-3657
	Dept. of Public Health	Water Quality	D. Elmo Lunn, Dir. Div. of Water Quality Control TN Dept. of Pub. Healtl 621 Cordell Hull Bldg. Nashville, TN 37219 (615) 741-2275
	Dept. of Public Health	Water Supply	David Droughon, Chief Drinking Water Quality Control TN Dept. of Pub. Healt 320 Capitol Hill Bldg. Nashville, TN 37219
	Dept. of Public Health	Industrial Waste	Stephen Anderson Enforcement & Monitori Section Div. of Water Quality Control TN Dept. of Pub. Healt Cordell Hull Bldg. Nashville, TN 37219 (615) 741-2275
	NPDES		
Air	Dept. of Public Health	Air Quality	Harold E. Hodges, P.E. Director Div. of Air Pollution Control TN Dept. of Pub. Healt 256 Captiol Bldg. Nashville, TN 37219 (605) 741-3931

Permit	Issuing Agency	Application	Responsible Person
Health & Safety	Dept. of Labor	OSHA	J. B. Richesin, Jr. Commissioner ATTN: Robert Taylor Dept. of Labor 501 Union Bldg. Suite A, Second Floor Nashville, TN 37219 (615) 853-2582

TABLE 96

TEXAS STATE PERMITS

Governor Bill Clements
State Capitol
Austin, Texas 78711

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Water Resources	Water Quality	Harvey Davis, Exec. Di: Dept. of Water Resources P. O. Box 13087 Capitol Station Austin, TX 78711 (512) 475-3187
	Dept. of Water Resources	Water Supply	Robert Bernstein, M.D. Commissioner of Health Dept. of Health Resources 1100 West 49th St. Austin, TX 78796 (512) 458-7375
	Dept. of Water Resources	Industrial Waste	Dick Whittington, Dep. Director Dept. of Water Resourc P. O. Box 13087 Captiol Station Austin, TX 78711 (512) 475-3761
Air	Air Control Board	Air Quality	Bill Stewart, P. E. Executive Director Air Control Boad 8520 Shoal Creek Blvd. Austin, TX 78756 (512) 451-5711
Health & Safety	Dept. of Health	Noise OSHA	David K. Lacker, Dir. Div. of Occup. Health and Radiation Control State Dept. of Health 1100 West 49th St. Austin, TX 78756 (512) 458-7341

TABLE 97

UTAH STATE PERMITS

Governor Scott M. Matheson
210 State Capitol
Salt Lake City, Utah 84114

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Div. of Health		Alvin Rickers, Acting Director Health Services Branch P. O. Box 2500 Salt Lake City, UT 841. (801) 533-6121
	Div. of Health	Water Quality	Calvin Sudweeks, Dir. Bur. of Water Quality 150 W. N. Temple Room 426 Salt Lake City, UT 841. (801) 533-6146
	Div. of Health	Water Supply	Gayle Smith, Chief Bureau of Water Quality 150 W. N. Temple Room 426 Salt Lake City, UT 841. (801) 533-4207
	Div. of Health	Industrial Waste	Calvin Sudweeks, Dir. Bur.of Water Quality 150 W. N. Temple Room 426 Salt Lake City, UT 841. (801) 533-6146
Air	Div. of Health	Air Quality	Alvin E. Rickers, Dir. Bureau of Air Quality 150 W. N. Temple Salt Lake City, UT (801) 533-6108
Health & Safety	Div. of Health	Noise OSHA	Larry F. Anderson, Chief of Radiation & Occup. Health Sect. 150 W. N. Temple Salt Lake City, UT 871. (801) 533-6734

TABLE 98

VERMONT STATE PERMITS

Governor Richard A. Snelling
Governor's Office
Montpelier, Vermont05602

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Agency of Environmental Conservation		Brendan J. Whittaker Secretary Agency of Environmenta Conservation Montpelier, VT 05602 (802) 828-3130
	NPDES	Water Quality	David L. Clough, Dir. Water Quality Section Waste Resources Div. Montpelier, VT 05602 (802) 828-2761
		Water Supply	Kenneth M. Stone, Chie Div. of Environmental Health 60 Main St. Burlington, VT 05401 (802) 862-5701 X56
		Industrial Waste	Richard Valentineeti Chief Air Pollution and Soli Waste Section State Office Bldg. Montpelier, VT 05602 (802) 828-3395
Air	Div. of Environmental Engineering Conservation	Air Quality	Richard Valentineeti Chief Air Pollution and Soli Waste Section State Office Bldg. Montpelier, VT 05602 (802) 828-3395
	PSD		

VERMONT Continued

Permit	Issuing Agency	Type of Application	Responsible Person
Health & Safety	Dept. of Labor and Industry	OSHA	Joel Cherington, Comm. Dept. of Labor & Ind. Montpelier, Vermont 05602 (801) 533-4000

TABLE 99

VIRGINIA STATE PERMITS

Governor John N. Dalton
State Capitol
Richmond, Virginia 23219

Permit	Issuing Agency	Type of Application	Responsible Person
Water	State Water Control Board, Bureau of Applied Technology	Groundwater Use Permit	Director 2111 N. Hamilton St. P. O. Box 1197 Richmond, VA 23230 (804) 257-6361
	NPDES		
Air	State Air Pollution Board	Air Quality	Executive Director Ninth Street Office Bl Richmond, VA 23219 (804) 786-3248
	PSD		
Health & Safety	VA Dept. of Labor and Industry Div. of OSHA Voluntary Compliance and Training	OSHA Occupational Safety	Director P. O. Box 12064 205 N. 4th St. Richmond, VA 23241 (804) 786-5875
	Dept. of Health, Bureau of Occupational Health	Occupational Health	Director James Madison Bldg. Richmond, VA 23219 (804) 786-6285
Land	VA Marine Resources Comm.	Wetlands Development Permit (If no local wetlands exist, in area where Wetlands Ord. is in effect; in any case, copies of aplication must be filed with both agencies)	Commissioner P. O. Box 756 Newport News, VA 23607 (804) 245-2811 Virginia Inst. of Mari Science Gloucester Pt. VA 2306 (804) 642-2111

Misc. N/A

REFINERY SITING REQUEST PROCESS

The Division of Industrial Development (Governor's Office) is responsible for assistance to prospective new industries in any activities related to the location of new plants. For site location assistance, contact: Director
Division of Industrial Development
State Office Building
Richmond, VA 23219
(804) 786-3791

Virginia has developed a "one-stop" program for environmental permitting. The Virginia Council on the Environment may be requested --at the applicant's discretion--to assist the applicant in obtaining the necessary permits.

TABLE 100

WASHINGTON STATE PERMITS

Governor Dixie Lee Ray
Legislative Building
Olympia, Washington 98504

Permit	Issuing Agency	Type of Application	Responsible Person

NOTE: Authority for the permit for a refinery of over 25 barrels a day capacity comes from the Governor of the State, after recommendation of the Siting Council which is made up of the heads of several state agencies dealing with the environment, health and safety, community development and economic development.

WEST VIRGINIA STATE PERMITS

Governor John D. Rockefeller IV
State Capitol
Charleston, West Virginia 25305

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Natural Resources		David C. Callaghan, Di 1800 E. Washington St. Charleston, WV 25305 (304) 348-2754
	Dept. of Natural Resources	Water Quality	David W. Robinson, Chi Div. of Water Resource 1201 Greenbrier St. Charleston, WV 25311 (304) 348-2107
	Dept. of Health	Water Supply	Robert McCall, Dir. Environmental Health Services State Office Bldg. 1800 E. Washington St. Charleston, WV 25305
	Dept. of Natural Resources	Industrial Waste	David W. Robinson, Chi Div. of Water Resource 1201 Greenbrier St. Charleston, WV 25311 (304) 348-2107
Air	Air Pollution Control Comm.	Air Quality	Carl G. Beard, II.,Dir 1558 E. Washington St. Charleston, WV 25311 (304) 348-3286
Health & Safety	Dept. of Labor	OSHA	Department of Labor Charleston Natl. Plaza Room 1726 700 Virginia St. Charleston, WV 25301 (304) 343-6181

TABLE 102

WISCONSIN STATE PERMITS

Governor Lee Sherman Dreyfus
State Capitol
Madison, Wisconsin 53702

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Natural Resources Bureau of Water Quality NPDES	Water Quality	Carl Blabaum, Dir. Box 7921 Madison, WI 53707 (608) 266-3910
Air	Dept. of Natural Resources Air Management Section	Air Quality	Director Box 7921 Madison, WI 53707 (608) 266-0603
Health & Safety	Dept. of Industry Labor and Human Relations	OSHA (Occupational Safety)	Department of Industry 201 E. Washington Ave. Madison, WI 53702 (608) 266-7552
	Dept. of Health and Social Services	(Occupational Health)	Donald Percy, Sec. One West Wilson St. Madison, WI 53702 (608) 266-3681
Land	N/A		
Misc.	Public Service Commission	Regulates Utilities, interstate pipelines, etc.	Stanley York, Chairman 4802 Sheboygan Ave. Madison, WI 53702 (608) 266-1241

REFINERY SITING REQUEST PROCESS

See following page

REFINERY SITING REQUEST PROCESS

A. Applicants submits air, water and solid waste permits to DNR
B. Environmental screening
C. Environmental impact statement if required
D. Public hearings
E. Final agency decision*

*Note: The Department of Natural Resources would be the "lead" state agency involved in refinery siting. Numerous approvals would be required from other state agencies but only one environmental impact statement process would be required if an EIS was determined to be needed. Most other state agency requirements involve the review of specific permit applications and may include the requirement for a public hearing.

TABLE 103

WYOMING STATE PERMITS

Governor Ed Herschler
Capitol Building
Cheyenne, Wyoming 82002

Permit	Issuing Agency	Type of Application	Responsible Person
Water	Dept. of Environmental Quality		Robert E. Sundin Hathaway Bldg. Cheyenne, WY 82002 (307) 777-7391
		Water Quality	William L. Garland, Adı Water Quality Div. Hathaway Bldg. Cheyenne, WY 82002 (307) 777-7781
		Water Supply	Robert Pinther Public Health Engr. Water Quality Div. Hathaway Bldg. Cheyenne, WY 82002 (307) 777-7752
	NPDES		
Air	Dept. of Environmental Quality	Air Quality	Randolph Wood, Admin. Air Quality Div. Hathaway Bldg. Cheyenne, WY 82002 (307) 777-7391
Health & Safety	Dept. of Labor	OSHA	Donald Owsley, Admin. OSHA 200 E. Eighth Ave. P. O. Box 2186 Cheyenne, WY 82002 (307) 777-7786
Land	N/A		

TABLE 104

LOCAL REQUIRED WATER PERMITS

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	
	x			x	x	x	x	Austin, TX °Wastewater Loading °Waterway Drainage °Water Quality (NEPA Standards)	Maureen McReynolds, Ph.D Director OERM 301 W. 2nd St. Austin, TX 78767 (512) 477-6511	
x					x			Columbus, OH °Sewage °Wastewater	Philip Amrose Dept. of Environmental Health City Hall Columbus, OH 43215 (614) 222-8191	*
		x		x	x		x	Little Rock, AR °Water Quality °Water Discharge Federal EPA Permit required AR Dept. of Poll. Control Permit required	Roy G. Brand 701 W. Markham St. Little Rock, AR 72201 (501) 371-4825	
x			x				x	Los Angeles, CA °Water rights °Water resources	State Water Resources Control Board 77 Cadillac Drive Sacramento, CA 95825 (916) 322-9118	*
								California Coastal Commission Review for coastal area sitings	California Coastal Comm. State Office 1540 Market St. San Francisco, CA 94102 (415) 557-1001	*

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience
e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

*See Permit Examples in Appendix

TABLE 104 (Cont'd)

LOCAL REQUIRED WATER PERMITS

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	*
x			x	x	x			New Haven, CT °Federal Clean Water Act °Coastal Site Plan Review Approval	David Holmes City Planning Department City Hall 195 Church St. New Haven, CT 06510 (203) 787-8200	
x			x				x	Oakland, CA °Water Quality	Regional Water Quality Control Board 1111 Jackson St. Oakland, CA 94607 (415) 464-1255	*
x					x		x	San Bernardino, CA °Water Course Changes °Surface Water Chgs. °Flooding °CA Environmental Quality Act Compliance	Environmental Review Committee City Hall 300 North D St. San Bernardino, CA 92418 (714) 383-5000	*
x							x	San Francisco, CA °Dredging ° °Pilings	U. S. Army Corps of Eng. 211 Main St. San Francisco, CA 94105 (415) 556-3660	*
x				x			x	South Bend, IN °Water Quality New Source Permit °State Board of Health °State Board of Water Pollution °Regional Planning Agency	John A. Cooney Office of the Mayor City Hall 1400 County-City Bldg. South Bend, IN 46601 (219) 284-9261	

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience
e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

LOCAL REQUIRED WATER PERMITS

*See Permit Examplesin Appendix K

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	*
	x	x			x			Tucson, AZ °Wastewater Discharge	James Robertson Pima County Dept. of Environmental Health 151 W. Congress Tucson, AZ 85701 (602) 792-8686	

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience

e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

LOCAL REQUIRED AIR PERMITS

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	*
		x		x	x		x	Anaheim, CA °Air Quality Under CA Env. Qual. Act Environmental Impact Report Required	Robert J. Kelley Associate Planner Planning Department City of Anaheim P. O. Box 3222 Anaheim, CA 92803 (714) 533-5721	*
	x						x	Chattanooga, TN °Air Quality Air Pollution Cont. Board	J. Wayne Cropp Director Air Pollution Cont. Bd. 3511 Rossville Blvd. Chattanooga, TN 37407 (615) 867-4321	
	x	x			x	x		Fresno, CA °Air Quality Fresno Mun. Code Art. 5, Env. Qual C. E. Q. A.	George A. Kerber, Director Planning and Inspection 2326 Fresno St. Fresno, CA 93721 (209) 488-1591	*
		x		x	x		x	Huntington Beach, CA °Air Quality C. E. Q. A.	Development Services Dept. Planning Division P. O. Box 190 Huntington Beach, CA 92648 (714) 536-5511	
x				x	x			Lansing, MI °Air Quality State Clean Air Plan	Vernon Fountain Zoning Administrator City Hall 124 W. Michigan Ave. Lansing, MI 48933 (517) 487-1412	

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience
e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

*See Permit Examples in Appendix K

TABLE 105 (Cont'd)

LOCAL REQUIRED AIR PERMITS

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	*
		x		x	x		x	Little Rock AR °Air Quality Federal E. P. A. Compliance needed	Roy G. Beard Jr. 701 W. Markham St. Little Rock, AR 72201 (501) 371-4825	
		x	x	x				Martinez, CA °Air Quality	Matthew Fouratt Planning Director 525 Henrietta St. Martinez, CA 94553 (415) 372-4900	*
		x		x	x	x		Rochester, NY °Air Quality if in environmentally sensitive area	John Spoelhof, Director Bureau of Planning & Zoning City Hall 30 Church St. Rochester, NY 14614 (716)428-7053	
		x		x	x	x	x	St. Petersburg, FL °Air Quality Local Zoning Performance Standards and State E. P. A	Ned Agee, Jr. Planning Dir. City of St. Petersburg City Hall 175 5th St. N St. Petersburg, FL 33731 (813) 893-7153	
		x						St. Jose, CA °Air Discharge °Permit to Construct °Permit to Operate	Bay Area Pollution Control District 939 Ellis St. San Francisco, CA 94109 (415) 771-6000	*

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience
e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

*See Permit Examples in Appendix

TABLE 105 (Cont'd)

LOCAL REQUIRED AIR PERMITS

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	*
x	x						x	<u>Washington, DC</u> °Air Quality Department of Environmental Services	Arthur Hatton Office of Planning and Development District of Columbia 1350 E St., N. W. Washington, DC. 20004 (202) 727-6514	
x				x	x	x		<u>Waterbury, CT</u> °Air Quality State of CT Environmental Regulation Compliance	Joseph E. Schiaroli City Planning City of Waterbury 235 Grand St. Waterbury, CT 06708 (203) 574-6832	
x	x			x	x			<u>Youngstown, OH</u> °Air Quality Environmental Review Committee if Community Development money is involved	Gary Singer Community Development Environmental Specialist City Hall 26 S. Phelps St. Youngstown, OH 44503 (216) 746-1892 X277	

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience
e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

*See Permit Examples in Appendix K

LOCAL HEALTH AND SAFETY REQUIREMENTS

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	*
x							x	<u>Denver, CO</u> °Fire Department Review	A. H. Jansen Zoning Administrator City and County Bldg. Denver, CO 80202 (303) 575-2191	
x					x			<u>Flint, MI</u> °Fire Code Compliance Permit °State OSHA Compliance	Gerald Childers Zoning Administrator 1101 N. Saginaw St. City Hall Flint, MI 48502 (313) 766-7346	
x			x	x	x			<u>Shreveport, LA</u> °Fire Prevention Code Permit °State OSHA Compliance	Stephen Pitkin Executive Director Metropolitan Planning Comm. P. O. Box 31109, Rm. 304 Shreveport, LA 71130 (318) 226-6480	
		x	x		x		x	<u>Signal Hill, CA</u> °Fire Marshall Review °State OSHA Compliance	Susan Thomason, Director Planning & Community Development 2175 Cherry Ave. Signal Hill, CA 90806 (213) 426-7333	
x	x			x			x	<u>Washington, DC</u> °Fire Code Compliance °Federal OSHA Compliance	Arthur Hatton Office of Planning & Development 1350 E St., N. W., Rm. 409 Washington, DC 20004 (202) 727-6514	

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience
e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

*See Permit Examples in Appendix

TABLE 107

LOCAL LAND USE REQUIREMENTS

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	*
x				x	x	x		Boise, ID °Conditional Use Zoning Permit	Susan Stacy, Director Planning Department 150 N. Capitol P. O. Box 500 Boise, ID 83702 (208) 384-4366	*
x				x	x	x	x	Denver, CO °Use Permit °Construction Plans review by Bldg. Dept. °Onsite approval by Bldg. Dept.	A. H. Jansen Zoning Administrator City and Council Bldg. Denver, CO 80202 (303) 575-2191	
x				x		x		Columbus, OH °Permitted only in M and M-1 Manufacturing Districts	N. Jack Huddle, Director Department of Development 140 Marconi Blvd Columbus, OH 43215 (614) 222-7763	*
x	x		x	x	x	x		Honolulu, HI °Zone Change if not within Zoning Code compliance	Permit Section Building Dept. and Dept. of Land Utilization City Hall Honolulu, HI 96813 (808) 523-4131	
x				x	x			Lansing, MI °Conditional Use for Zone Change	Vernon Fountain Zoning Administrator City Hall 124 W. Michigan Ave. Lansing, MI 48933 (517) 487-1412	

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience
e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

*See Permit Examples in Appendix K

TABLE 107 (Cont'd)

LOCAL LAND USE REQUIREMENTS

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	*
	x			x	x	x	x	Mesa, AZ °Conditional Use	Howard W. Godfrey Planning Director Planning and Zoning Board 55 N. Center St. Mesa, AZ 85201 (602) 834-2385	*
x				x	x	x		New Haven, CT °Special exception Sec. 42T of Zoning Ordinance	David Holmes City Plan Department City Hall 195 Church St. New Haven, CT 06510 (203) 787-6379	
x	x			x	x		x	Paterson, NJ °Variance required	George Ferensick Director of Planning Dept. of Community Development City Hall 155 Market St. Paterson, NJ 07505 (201) 881-3305	*
	x			x	x			Portland, OR °Conditional Use	Frank N. Frost Bureau of Planning Code Administration 424 S. W. Main St. Portland, OR 97204 (503) 248-4253	*

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience
e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

*See Permit Examples in Appendix

TABLE 107 (Cont'd)

LOCAL LAND USE REQUIREMENTS

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	*
		x		x	x	x		San Bernardino, CA °Conditional Development Permit °State Land Commission Permit (for siting on or adjacent to State controlled land)	Douglas McIsaac Planning Department 300 North D St. San Bernardino, CA 92418 (714) 383-5057	* *
x					x		x	Springfield, MA °Special Use Permit	Planning Dept. City of Springfield 36 Court St. Springfield, MA 01101 (413) 736-2711	*
		x			x		x	Signal Hill, CA °Zoning Change (New Regulations now being formulated) °State Land Commission Permit (For siting on or adjacent to state controlled lands)	Susan Thomason, Director Dept. of Planning and Community Development City Hall Signal Hill, CA 90806 (213) 426-7333	*
x				x	x	x	x	Waterbury, CT °Special Exception by Z. B. A.	Joseph E. Schiaroli Building Official 235 Grand St. City Hall Waterbury, CT 06708 (203) 574-6832	

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience
e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

*See Permit Examples in Appendix K

TABLE 107 (Cont'd)

LOCAL LAND USE REQUIREMENTS

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	*
		x		x				Worcester, MA °Special Use 1. Apply to Bldg. Dept. 2. If refused, apply Z.B.A. for a. Variance or b. Special Permit	Carl Gordon, Chairman Zoning Board of Appeals City Hall Worcester, MA 01608 (617) 798-8111	*

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience
e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

*See Permit Examples in Appendix K

TABLE 108

MISCELLANEOUS LOCAL REQUIREMENTS

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	*
x					x		x	Columbus, OH °Noise Control	N. Jack Huddle, Director Department of Development 140 Marconi Blvd. Columbus, OH 43215 (614) 222-7763	
x				x				Erie, PA °Odorous Matter	Leonard Nowak Erie Planning Commission 626 State St. Erie, PA 16501 (814) 456-8561	
x								Flint, MI °Traffic Engineering Review	Gerald Childers Zoning Administrator City Hall 1101 N. Saginaw St. Flint, MI 48502 (313) 766-7346	
x	x			x	x	x		Honolulu, HI °Special Management Area Permit Shoreline Protection Laws	Environmental Quality Comm. 550 Halekauwila St. Room 301 Honolulu, HI 96813 (808) 548-6915	
x				x			x	New Haven, CT °CT Coastal Management Act of 1979 Impact Review	David Holmes City Planning Department City Hall 195 Church St. New Haven, CT 06510 (203) 787-8200	

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience
e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

*See Permit Examples in Appendix K

MISCELLANEOUS LOCAL REQUIREMENTS

a	b	c	d	e	f	g	h	Selected Cities	Responsible Local Office	*
x								San Francisco, CA °Dredging San Francisco Bay Area Conservation and Development Commission	San Francisco Bay Area Conservation and Development Commission 30 Van Ness Ave. Room 2011 San Francisco, CA 94102 (415) 557-3686	*
		x		x	x			Santa Ana, CA °Noise °Light °Vibration °Refuse matter	Planning Department 20 Civic Center Plaza Santa Ana, CA 92701 (714) 834-4134	
x			x	x	x			Waterbury, CT State Inland Wetland Approval	Joseph Schiaroli Building Official 235 Grand St. City Hall Waterbury, CT 06708 (203) 574-6832	
		x			x			Winston-Salem, NC °Electro-magnetic interference °Noise °Odorous Matter	City Council Planning Bd. P. O. Box 2511 Winston-Salem, NC 27102 (919) 727-2087	*
	x		x					Worcester, MA °Noise °Vibration °Flashing	Mr. Francis Donahue, Dir. Bureau of Land Use Control City Hall Worcester, MA 01608 (617) 798-8111	

a. Strong Mayor
b. Weak Mayor-Strong Council
c. City Manager
d. Refinery Experience
e. Requires Zoning Change
f. Requires Council Approval
g. Requires Public Hearing
h. Requires Planning Approval

*See Permit Examples in Appendix K

5.0 ISSUES, CONCERNS AND MITIGATING RESPONSES

There are numerous impacts both positive and negative that can be identifed as the result of the construction of a major domestic refinery project. These considerations were discussed in the socio-economic review in Section 3.9. This discussion is presented to identify specific refinery-related issues, concerns and mitigating responses that were found from the literature and survey responses.

The National Environmental Policy Act (NEPA) process and the Council of Environmental Quality (CEQ) Guidelines form the framework for addressing issues, concerns, and mitigating responses for a refinery set-up or modification project. There's no way of predicting which level of government will play the most important role as each level will identify significant issues. As the review is in process, the major issues and concerns and the associated level of government will emerge and focus the industrial responses.

An example of a key federal concern might be the impact of increased air emissions in a PSD region. A state level major concern could be nonattainment procedures or region-wide socio-economic impacts. Key local government concerns deal with a variety of citizen issues and site specific physical impacts. The NEPA process intertwines all levels of government in the environmental review of an industrial or other major impact process.

The issues and concerns raised during the NEPA - CEQ review process are significant. These concerns, however, seem to repeat when considering most major heavy industry projects, not just petroleum refineries. An example of the types of concerns raised by rural communities are shown in the Table 109. The new CEQ guidelines require an early scoping meeting by the lead agency to highlight the project concerns. The summary report of this meeting ranks the issues in order of priority and publishes the lists of questions raised by each category of concern. This scoping concept is a very helpful, early planning tool which will assist the project proponent to understand the basis and depth of the project sentiment.

This procedure is a federal level mitigating response to the

TABLE 109

RANKING OF CONCERNS FOR TWO PROPOSED NORTH CAROLINA REFINERY PROJECTS

Concerns	Project 1 Rank*	Project 2 Rank**
Social and Economic	1	4
Oil Spills	2	3
Water Quality	3	1
Air Quality	4	5
Plants and Wildlife	5	2
Wastes	6	7
Land Use	7	9
Related Industrial Development	8	8
Public Health and Safety	9	6
Transportation	10	10
Odors	11	11
Aesthetics	12	20
Demographic Changes	13	-
Limitations and Modifications	14	19
Noise	15	-
Proposed Refinery Design	16	12
Geological and Seismic	17	26
Diaster	18	13
Obsolescence	19	25
Archaeological and Historic Resources	20	24
Financial Feasibility	21	16
Existing Facilities	22	14
By-Products	23	23
Fire Prevention and Protection	24	-
Availability of Refined Products	25	-
Sulfur Handling	26	27
Refinery Rejections	27	-
Sources of Oil	28	29
Miscellaneous	29	30
Construction and Dredging	30	22
Weather	31	28
Pipelines	32	15
Tank Farms	33	-
Easements	34	-
Complaints	35	-
Alternative Sites	36	17

*Scoping Report from the Brunswick Energy Company Meeting
**Scoping Report from the Carolina Refining and Distributing Company Meeting

environmental analysis of a proposed project. These federal regulations act as a check to unbounded industrial growth and expansion. The same type of check is shown by well-intentioned environmental preservation interests such as the Audobon Society, Sierra Club, Friends of the Earth, and many other organizations. At present, the balance appears to favor the no-growth or very limited growth positions.

One of the steps in the environmental assessment and EIS process is the determination of the project's economic justification. Widely divergent results have been published concerning the need for major refinery projects. Several EIS's , the Hampton Roads Energy Company, Pittston Refinery Company, Alaska Petroleum Company among others, have docummented the need to construct domestic refineries. More than economics must be demonstrated to increase the project acceptance.

From the twenty state survey responses, several states have attempted to standardize the siting and environmental review procedures. Virginia's response to industrial consideration has been to establish a state department to lend assistance to industries considering location within the state. (Appendix 0-3) This procedure, however, does not assure local acceptance since the HamptonRoads Energy Company has gone through a very costly and lengthy review and has only recently received its permits from the Secretary of the Army. North Carolina has set up standard procedures and both inter-agency and public review committees to consider the Brunswick Energy Company siting proposals. (Appendix 0-4) They have also published a summary permit tabulation for easy reference to state agencies. The State of Washington reviews documents on the laws and siting rules for energy facilities, Appendix 0-5 and 0-6 respectively, in order to make known the state-wide considerations. Other states have attempted to streamline siting and permit requirements by legislative or administrative procedures (Appendix 0-7). These state level mitigating responses are an attempt to assist an industrial project through the regulatory maze. However, in no manner do these procedures try to compromise environmental quality considerations.

One survey answer from the selected cities showed a quantitative site evaluation system (Appendix 0-8). This response by the Association of Bay Area Governments in California is an attempt to rank alternate sites by specific analysis procedures.

From the information reviewed during the course of this workbook preparation, it can be shown that significant environmental concerns can result from the siting of a new refinery or the major modification/expansion of an existing facility. The regulatory and permitting process offers a series of review steps which do contribute to the enchancement of the human quality of life. Mitigating responses to the environmental concerns from both the technical process design and regulatory process have been identified which should assist the acceptance of these energy projects in an environmentally responsible manner.

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APPENDICES

APPENDIX A

GLOSSARY

A

ABSORPTION: A process whereby a liquid dissolves a gas, such as amine which absorbs hydrogen sulfide (H_2S) from fuel gas.

ACCUMULATOR: A vessel which serves as a collection point for condensed products, such as tower overhead material.

ACID GAS: A gas containing hydrogen sulfide and carbon dioxide.

ACID GAS TREATING: Process where acid gases are removed from hydrocarbon gases by absorption in amine solution.

ACTIVATED CARBON: A form of carbon which has a high adsorptive capacity for chemical species contained in gases, vapors and liquids.

ADDITIVES: Chemicals added to petroleum products to improve performance or obtain desired product characteristics.

ADSORPTION: A process in which chemical species contained gases, vapors or liquids physically adhere to the surface of a solid, such as activated carbon.

ALKYLATION: A catalytic process for combining isoparaffins and olefins such as isobutane and butylene, to form alkylate, a gasoline component. Extremely important in the production of unleaded gasoline.

AMINE: Organic chemical used to absorb acid gases from hydrocarbon gases in the acid-gas treating unit.

ANTI-KNOCK COMPOUNDS: An additive to gasoline, such as tetraethyl, lead, for improving combustion characteristics in internal combustion engines.

API GRAVITY: An index for measuring the density of crude oil and petroleum products. The higher the gravity, the lighter (less dense) the material.

API SEPARATOR: A device for separating oil from water by gravity differential.

AROMATIC HYDROCARBONS: Hydrocarbons with an unsaturated closed ring structure, such as benzene, toluene and xylene.

ASH: A non-volatile, incombustible component of fuels which remains after combustion.

B

BACT: Refers to level of air and wastewater control technology defined as Best Available Control Technology.

BALLAST: The flow of waters from a ship which is treated at the refinery.

BARREL: A volume unit used in the petroleum industry consisting of 42 U.S. standard gallons.

BASELINE: Present and future conditions as they would exist in the absence of a proposed action.

BASIC EMPLOYMENT: Employment that responds to demand or to other determinants (e.g., political forces) that are external to the local economy.

BASIC INCOME: Income directly associated with basic employment or that in some way is due to determinants that are external to the local economy.

BEST AVAILABLE TECHNOLOGY ECONOMICALLY ACHIEVABLE (BATEA or BAT): The treatment required by July 1, 1984, for industrial discharge to surface water.

BEST MANAGEMENT PRACTICES (BMP): Treatment requirements, operating and maintenance procedures, and other management practices to control plant site runoff.

BCT: Refers to level of air and wastewater control technology defined as Best Control Technology.

BPCT: Refers to methods of wastewater treatment defined as Best Practical Control Technology.

BOD_5: Biochemical Oxygen Demand. A measure of the oxygen required by micro-organisms to biologically degrade a wastewater. Usually measured over five days.

BLOWDOWN: Material purged from refining processes during startups, shutdowns, and pressure relieving. Aqueous blowdowns also occur from cooling water and boiler systems as a part of normal operation.

BS&W: Bottom sediment and water material found in tank bottoms.

BTU: British thermal unit - used to define heating value of fuels. The heat required to raise one pound of water one degree of Fahrenheit.

BUNKER FUEL OIL: A heavy residual fuel oil used mainly by ocean-going vessels.

C

CATALYST: A substance used to increase the rate of chemical reactions but which is not directly involved in the reaction. Solid refinery catalysts are usually made from platinum or other heavy metal. Liquid catalysts are acids such as Hydrofluoric Acid (HF).

CAUSTIC: A term used for solutions of sodium hydroxide used in various treating and sweetening processes.

CLAUS PROCESS: A sulfur recovery process in which hydrogen sulfide is converted to elemental sulfur.

CLEAN AIR ACT: CAA

CLEAN WATER ACT: CWA

COD: Chemical Oxygen Demand. A measure of the oxygen equivalent of that portion of the organic matter in a wastewater that can be oxidized by a strong chemical oxidant.

COHORT: A group used usually in the context of a group of the population of the same age or sex.

COKE: Solid carbonaceous residue obtained from coking residual crude oil. Calcined coke is coke that has been heat treated to remove volatile materials.

COKING: Thermal cracking process in which vacuum distillation unit residuum is converted to lower boiling range material and coke.

CRACKED GASOLINE: Gasoline obtained by cracking heavier petroleum fractions.

CRACKING: A process in which large hydrocarbon molecules are divided into smaller molecules. Processes may be catalytic or thermal types.

CRUDE OIL: Raw material used for refinery feedstock.

D

DATA BASE: A large accumulated file of information organized for analysis, usually in machine readable form for access by users via computer.

DEAERATOR: A divide used to remove dissolved oxygen from boiler feed water.

DEBUTANIZER: See De-dethanizer.

DE-ETHANIZER: A distillation colum which removes ethane and lighter hydrocarbons from propane and heavier hydrocarbons. The terms depropanizer and debutanizer are also used for similar operations.

DIESEL FUEL: A petroleum product used as fuel in diesel engines consisting of gas oils.

DEPROPANIZER: See De-ethanizer.

DESALTING: A process in which salts are removed from crude oil by washing with water. In some cases desalting may take place in the presence of an electrostatic charge to and in oil-water separation.

DISTILLATION: A process in which a hydrocarbon feed is separated in various components of different boiling points.

DRY GAS: A hydrocarbon gas which does not condense easily or contain water vapor. Usually contains mostly light hydrocarbons, such as methane and ethane.

E

ECONOMIC BASE: The economic base of an economy refers to either the total of its basic income or its basic employment.

ENDOTHERMIC: Reaction or process which requires heat to take place.

ECONOMETRIC MODEL: A model of the economy that emphasizes the relationship of production to income, and of income to demand. These models are usually estimated statistically from time series data.

ENTRAINMENT: Liquid droplets or mist contained in vapors leading a boiling liquid.

EXOTHERMIC: Reaction or process which produces heat as it proceeds.

EXTRACTION: Process in which a substance is removed from a liquid stream by contacting with a second, immisible liquid (liquid-liquid extraction). Can also have gas-liquid extraction where one stream is a gas.

F

FACILITIES/SERVICES: Used here to refer both to those facilities and services provided primarily by the private market but having significant public sector leakages, such as housing or health services, and to those facilities and services usually provided by the public sector like public safety, water supply, wastewater treatment, transportation or recreation.

FISCAL: Concerned with the finances of governmental units, both on the expenditure side and the revenue side.

FIXED ROOF: A tank roof which is rigidly fixed to the tank regardless of the tank liquid level.

FLARE: A device used for burning waste gases and is usually part of the relief valve system.

FLASH DRUM: A vessel used to separate vapors and liquids after a pressure reduction.

FLASH POINT: The minimum temperature at which vapors above a petroleum fraction or product will ignite in the presence of a flame.

FLOATING ROOF: A roof which floats on surface of liquid in a storage tank to reduce evaporation losses.

FLUID CATALYTIC CRACKING: High temperature, low pressure catalytic process which converts (cracks) higher boiling range fractions into lower boiling range materials.

FRACTIONATOR AND FRACTIONATION: See Distillation.

FUEL GAS: Light hydrocarbon gases consisting mainly of methane and ethane, generated by the refining processes and used for firing process heaters and furnaces.

FURNACE OIL: Distillate fuel oil used for residential and commercial heating. Also known as No. 2 Fuel Oil.

G

GAS OIL: A fraction obtained in the distillation of petroleum generally used in distillate fuel oil.

GASOLINE: Refined petroleum naphtha used in internal combustion reciprocating engines.

GRAVITY: See API Gravity.

H

HAZARDOUS WASTE: A solid waste which because of its quantity, concentration, or physical, chemical or infectious characteristics, may pose a substantial hazard to human health or the environment when improperly handled.

HEAVY CRUDE OIL: Viscous crude oils with API gravities less than 16.

HYDRODESULFURIZATION: A process in which sulfur, nitrogen and metals are removed from petroleum in the presence of a catalyst by combining the sulfur with hydrogen.

HYDROTREATING: A process in which petroleum is reacted with hydrogen in the presence of a catalyst to remove sulfur or to hydrogenate unsaturated compounds. Often used interchangeably with hydrodesulfurization.

HYDROCRACKING: A high temperature, high pressure catalytic process which cracks petroleum fractions in the presence of hydrogen. ~~Also~~ will perform some degree of hydrodesulfurization and hydrogenate unsaturated compounds.

I

IMMISCIBLE: Two materials are immiscible if they will not dissolve in each other, such as oil and water.

INPUT-OUTPUT: An economic modeling technique that focuses on the purchases and sales that take place between individual industries.

INVENTORY TEST: A list of chemicals manufactured or processed in the United States.

ISOMERIZATION: A process in which normal hydrocarbons are converted to their isomers by rearranging the molecular structure. The final product called isomerate is used as a blending component in gasoline.

JET FUEL: A kerosene-based fuel for use in gas turbine powered aircraft. JP-4 and JP-5 are common grades of jet fuel.

K

KEROSENE: A petroleum distillate boiling between naphtha and gas oil. Used in jet fuels and heating oils.

KNOCKOUT DRUM: A process vessel used to remove entrained liquid from gases.

L

LABOR FORCE: The sum of the employed and the unemployed.

LABOR FORCE PARTICIPATION RATE: The percent of any given group of the population that is in the labor force, i.e., employed plus unemployed.

LEAD: Refers normally to lead additives in gasoline, such as tetraethyl lead.

LIGHT: A relative term applied to petroleum fractions to denote the lower boiling material, such as light naphtha and light gas oil.

LIGHT ENDS: Light liquid hydrocarbons, typically ethane, propane and butane.

LINEAR RELATIONSHIP: Of the first degree with respect to one or more variables; involving measurement in one dimension only.

LPG: Liquefied petroleum gas. A petroleum product containing propane and butane.

LOADING RACK: A structure used to load petroleum products into seagoing vessels, tank trucks, rail tank cars, or barges.

LOCAL IMPACT AREA: The area within which the margin demographic impacts of a proposed action will be felt.

LOWEST ACHIEVABLE EMISSION RATE: For any source, the rate of emissions which reflects - 1) the most stringent emission limitation which is contained in the SIP for such class or category of source, or
2) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent.

M

MISCIBLE: Two materials are miscible if they will dissolve in each other, such as salt and water.

MERCAPTAN: An organic compound present in "sour" crude oils or gasolines. Mercaptan compounds contain sulfur and have a strong odor.

METHANATION: A process in which carbon monoxide is converted to methane by reaction with hydrogen.

METHODOLOGIES: Systems of practices or procedures. The procedures deal with the components of an environmental impact assessment.

MITIGATION: To lessen or reduce. Used in the context of environmental assessments to refer to an action designed to reduce adverse impacts.

MODIFICATION: Any physical change in, or change in the method of operation of, an existing facility which increases the amount of pollution being discharged.

MULTIPLIER: A term used by economists to describe the process by which a change in basic income or basic employment results in a change in total income or employment that is larger than the original change.

N

NAPHTHA: A petroleum fraction boiling in the gasoline range.

NAPHTHENES: A group of hydrocarbons having a saturated ring structure such as cyclohexane found in naphthenic crude oils.

NAPHTHENIC ACID: A corrosive organic acid found in some naphthenic crude oils.

NATIONAL AMBIENT AIR QUALITY STANDARDS: A maximum concentration of pollutants legally permissible anywhere in the country.

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS STANDARDS: Emission standards which apply to all industries which emit any hazardous pollutants.

NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM: The national program for issuing permits pursuant to the Clean Water Act. The term includes any state program approved by the EPA.

NEW SOURCE: Any stationary source, the construction or modification of which is commenced after the publication of regulations prescribing a standard of performance.

NEW SOURCE PERFORMANCE STANDARDS: EPA-issued standards which define the levels of pollution which can be emitted or discharged from a source.

NONATTAINMENT: A regulatory program requiring preconstruction approval of any new plant with significant potential emissions to be built in an area where the NAAQS are "not" being met.

NON-BASIC EMPLOYMENT: Employment that responds to levels of demand originating within the local economy.

O

OCTANE NUMBER: An index used to measure the anti-knock properties of gasoline. Research, Motor and Road Octane Numbers are three different octane ratings.

ODORANT: A material added to fuel gas to impart a distinctive odor and permit human detection.

OFFSETS: An amount of pollution reduced from existing sources which exceed projected amount of pollution from a new source (nonattainment areas).

OLEFINS: A class of hydrocarbons which are "unsaturated" or deficient in hydrogen, such as ethylene, butylene.

ON STREAM: A term to denote that a refinery or process unit is in normal operation.

OVERHEAD: The vapors which are boiled off the top of a distillation tower or the lightest product obtained in the distillation process.

P

PARAFFIN: A series of linear and branched hydrocarbons fully saturated in hydrogen, such as methane, propane. Also known as alkanes. High molecular weight paraffin in solid form is known as paraffin wax.

PREVENTION OF SIGNIFICANT DETERIORATION: A regulatory program requiring preconstruction approval of any new plants with significant potential emissions to be built in an area where the NAAQS "are" being met.

PRIORITY LIST: A list of chemicals which require testing to determine if they could cause harm.

psia, psig: Pressure designations in pounds per square inch. Psig is the actual reading of a pressure gauge and psia is psig plus atmospheric pressure.

PUBLIC OWNED TREATMENT WORKS: A treatment works which is owned by a state or municipality.

R

REBOILER: A heat exchanger used to boil liquid to provide vapors to the bottom of a process column.

REDUCED CRUDE OIL: The crude oil remaining after distillate products have been removed in the crude distillation process. Typically is the feedstock to the vacuum distillation unit.

REFLUX: That portion of the overhead vapors that is condensed and returned to the process column.

REFORMING: A process in which the octane rating of naphtha is increased by catalytic reaction or mild thermal cracking. The product is termed reformate and used as a blending component in gasoline.

RESIDUAL FUEL OIL: Fuel oils containing reduced crude oil.

S

SATURATED HYDROCARBON: Hydrocarbons that have no deficiency of hydrogen such as methane and ethane.

SAYBOLT-FUROL, SAYBOLT-UNIVERSAL: Measures of viscosity used in petroleum industry.

SHIFT CONVERTER: A reactor used to convert two compounds to two different compounds, such as are used in sulfur plants and hydrogen plants.

SKIMMING: Distillation of crude oil to remove light fractions only. Also known as topping.

SLOP OIL: Mixture of oils lost through blowdown, spillage, process upset, etc. Usually recovered and reprocessed.

SOUR: Containing sulfur compounds such as hydrogen sulfide, as in sour gas or sour crude oil. Sour crude oil is defined as having more than 0.5% (wt) of total sulfur.

STABILIZER: A distillation process which removes light ends from petroleum liquids, generally butanes, from naphthas.

STATE IMPLEMENTATION PLANS: A required EPA state document which contains the actual abatement requirements devised to reduce air pollution to a level meeting NAAQS.

STRAIGHT RUN: Products directly obtained from distillation of crude oil before undergoing chemical change, such as cracking or reforming.

STRIPPING: The removal of volatile products by direct countercurrent contact with a stripping medium, such as steam.

SWEET: Containing little sulfur or sulfur compounds, such as hydrogen sulfides and mercaptans.

T

TEL: Tetraethyl lead.

TAIL GAS: Sulfurous gases unreacted in sulfur recovery process.

TAIL GAS TREATING: Processes which remove the residual sulfur compounds present in sulfur recovery unit tail gas.

TAR: Highly viscous polymerized residue produced in a vacuum distillation, cracking coils. By-product of the cracking process.

TOPPED CRUDE: Residual crude oil obtained in topping plant.

TOPPING: See Skimming.

TOWER: A vertical vessel in which petroleum is distilled, or gases are absorbed, etc.

TREATING: A process in which petroleum is contacted with chemicals to improve product quality.

TURNAROUND: A maintenance operation in which a refinery or process unit is shut down and repaired.

U, V

VACUUM DISTILLATION: Separation of crude oil by distillation at pressures below atmospheric.

VAPOR PRESSURE: Pressure exerted by a liquid at a given temperature in a closed vessel in the absence of air or other compounds.

VAPOR RECOVERY: A system used to collect hydrocarbon vapors from vents and and relief devices for reuse in the refinery.

VIRGIN STOCK: See Straight Run.

VISCOSITY: A measure of resistance to flow, often determined by the time for liquid to pass through standard orifice.

W

WET GAS: Fuel gas containing condensable hydrocarbon vapors.

APPENDIX B

ABBREVIATIONS

AQCR	Air Quality Control Regions
BACT	Best Available Control Technology
BAT or BATEA	Best Available Technology Economically Achievable
BCT	Best Conventional Technology
BMP	Best Management Practices
BOD_5	Five-day Biological Oxidation Demand
BPCT	Best Available Control Technology
BS&W	Bottom Sediment and Water
BTU	British Thermal Unit
CAA	Clean Air Act
CAA§110	Section 110 of the Clean Air Act
CFR	Code of Federal Register
COD	Chemical Oxygen Demand
CWA	Clean Water Act
CWA§110	Section 110 of the Clean Water Act
EPA	United States Environmental Protection Agency
FCC	Fluid Catalytic Cracking Unit
LAER	Lowest Achievable Emission Rate
LPG	Liquefied Petroleum Gas
$\mu g/m^3$	Micrograms Per Cubic Meter
NAAQS	National Ambient Air Quality Standards
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standard
POTW	Public Owned Treatment Works
PSD	Prevention of Significant Deterioration
SIP	State Implementation Plan
SPCC	Spill Prevention Control and Countermeasure Plan
TEL	Tetraethyl Lead
TSS	Total Suspended Solids

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