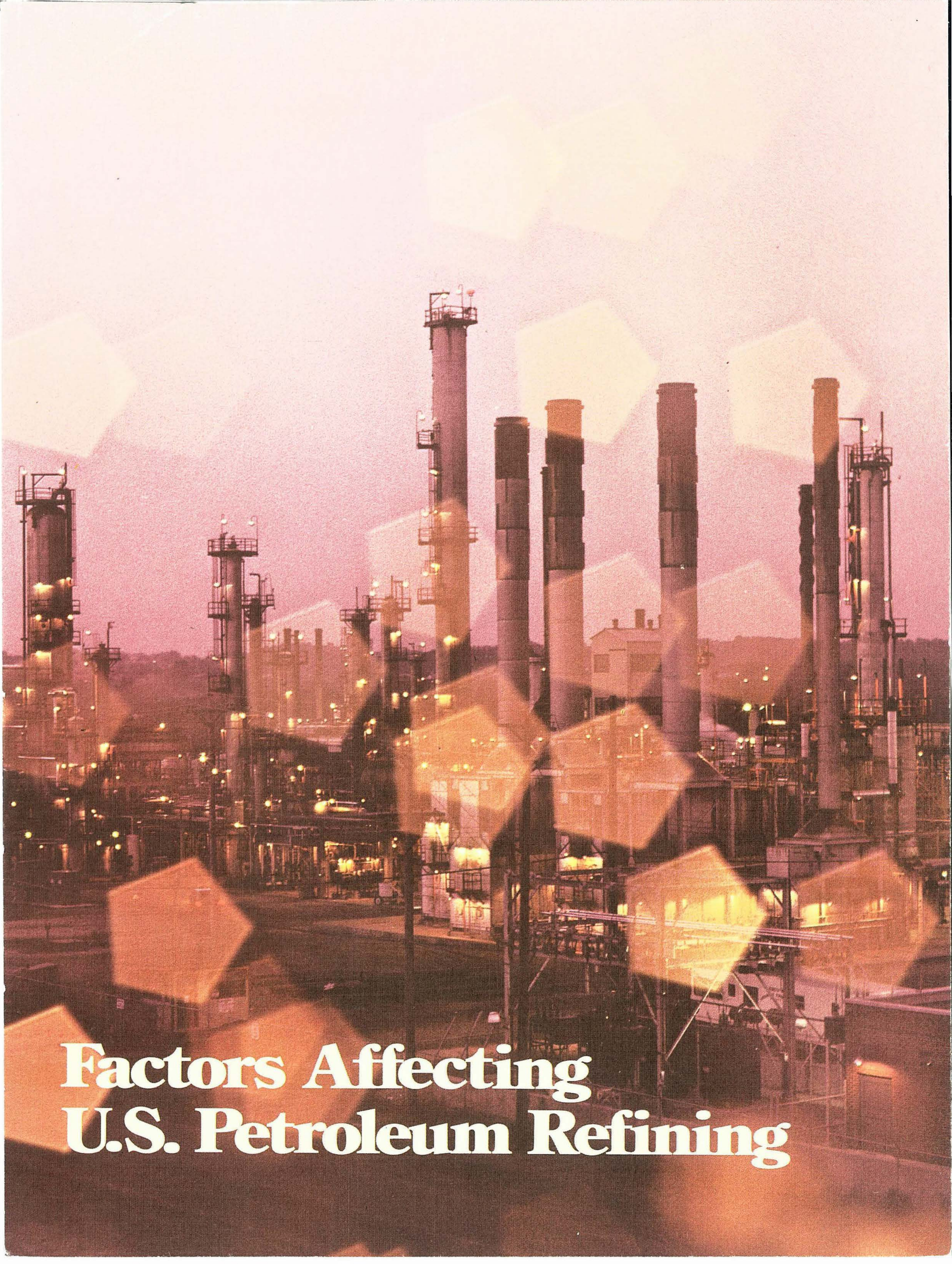

Factors Affecting U.S. Petroleum Refining

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May 1973

Prepared by the
National Petroleum Council's Committee
on Factors Affecting U.S. Petroleum Refining
Orin E. Atkins, Chairman
with the Assistance of the Coordinating Subcommittee
George Holzman, Chairman

NATIONAL PETROLEUM COUNCIL

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PREFACE

On February 9, 1972, the National Petroleum Council, an officially established industry advisory body to the Secretary of the Interior, was requested by the Assistant Secretary of the Interior for Energy and Minerals to undertake a survey of the factors--economic, governmental, technological and environmental--which affect the ability of domestic refining capacity to respond to demands for essential petroleum products. The Assistant Secretary asked that the Council's report discuss those elements which are considered essential to the development of domestic refining capacity. (See Appendix A for request letter.)

In response to this request, the National Petroleum Council established a Committee on Factors Affecting U.S. Petroleum Refining under the chairmanship of Orin E. Atkins, Chairman of the Board, Ashland Oil, Inc., and the cochairmanship of Hon. Stephen A. Wakefield, Assistant Secretary of the Interior for Energy and Minerals. The Committee was assisted by a Coordinating Subcommittee, chaired by George Holzman, General Manager, Refineries, Shell Oil Company. (See Appendix B for Committee rosters.) This report is designed to call attention to those factors and issues which have affected domestic refining capacity.

The results of the Committee's investigation and the detailed findings contained in this report are the basis of the National Petroleum Council's report, *Factors Affecting U.S. Petroleum Refining--A Summary*, published in May 1973. In addition, the Committee undertook to supplement a previous NPC report entitled, *Impact of New Technology on the U.S. Petroleum Industry (1946-1965)*. The review as regards refining technology was made in April 1973 with a separate report published in September 1973.

Since publication of the Summary Report in May 1973, many events have taken place which will have an impact on the U.S. petroleum refining industry. These include: (1) changes in the oil import policy, (2) spiraling world crude oil prices--elasticity of price to demand, (3) energy conservation measures, (4) producer country ownership of oil production and interest--export refineries, (5) oil embargo, (6) U.S. price stabilization, etc.

This complete and final report of the NPC Committee on Factors Affecting U.S. Petroleum Refining was based on an analysis of conditions and circumstances which contributed to the lag in development of U.S. refining capacity prior to early 1973. Events since then, however, could have far more serious implications for the future of the refining industry in the United States. Although the final report of the NPC Committee is lacking the evaluation and analysis of these current events, it presents a record of the economics, technology and prevailing policies of the Federal Government during the early years of the 1970's which contributed to spot shortages of petroleum products and a very serious lag in construction of petroleum refining capacity.

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Extracted from
Factors Affecting U.S. Petroleum Refining—A Summary
Prepared by the National Petroleum Council May 1973

INTRODUCTION

Refining is an integral part of the domestic petroleum industry. It is only through this process that crude oil can be transformed into the many varied products which have become the basis for the Nation's continued development. Refined petroleum products form the basis for heating oils, motor fuels, plastics, building materials, synthetic fibers, medicines, rubber, paint solvents, biodegradable detergents, asphalt and lubricating oils, as well as many other products.

The petroleum industry, which has been called upon to supply the Nation's consumers with three-fourths of their energy needs, is a complex web of interrelated functions. In total, over 40,000 companies perform the primary functions of exploration, production, transportation, refining and marketing. This report is addressed primarily to the refining function.

The growth of the domestic refining segment of the petroleum industry is affected by the growth of the other segments. For example, domestic oil and gas production rates directly affect the amount and location of refining capacity requirements. Similarly, the development of transportation systems which allow the United States to realize the benefits of large modern tankers affect refiners' decisions regarding size and location of new refinery sites.

There are nearly 200 companies in the continental United States which are directly involved in the process of crude oil refining. These refineries are located in 40 states and range in capacity from 250 barrels per calendar day (250 B/CD) to over 400,000 barrels per calendar day (400 MB/CD).*

U.S. refiners have a highly diverse range of economic and industrial interests. Some refiners employ simple distillation techniques for the production of the most elemental refined products, while others are largely engaged in the manufacture of motor fuels and domestic heating oils. Still others produce a broad spectrum of petroleum products, including highly sophisticated petrochemicals. The various processing techniques and types of equipment employed in the manufacture of finished petroleum products are numerous. Because of the diversified interests, manufacturing techniques and raw materials base, different refining facilities have different interests and requirements.

This report attempts to delineate broad areas of concern to refiners and to suggest policy options which will help maintain the health and viability of the refining segment of the petroleum industry.

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* Since product demands are expressed as daily averages, daily average or calendar day refinery capacities are used throughout this report. Specific process unit capacities are expressed in rated or stream day capacities.

While numerous factors will be discussed in the body of the report, the single most influential factor on U.S. petroleum refining today--and indeed on the entire petroleum industry--is the current transition from operating in an era of stable and ample domestic crude and product supplies to operating in an era of instability and shortage. Refiners are no longer assured of the availability of needed raw materials of either the quantity or the quality for which their refineries were designed.

This NPC study addresses the past, present and future trends in domestic petroleum refining in relation to requirements, capacities and capabilities. In addition, technological factors that have contributed to the shortfall in domestic refining capacity are evaluated. To determine past, current and near-term refining capacity, extensive surveys were conducted, the composite results of which are used throughout Part Two of this report.

In order to analyze the construction of new refining capacity, the study addresses the economic factors which indicate the advantages and disadvantages of building domestic refineries *versus* building refineries in foreign perimeter locations such as eastern Canada and the Caribbean. Oil import policy, environmental considerations and other pertinent government policies are evaluated.

Due to the scope and complexity of the assignment, this study is presented in three volumes. The Summary Report of May 1973 contains the conclusions and recommendations of the National Petroleum Council and incorporates a summary of this volume. The third volume is an update of the refining section of a previous NPC report entitled, *Impact of New Technology on the U.S. Petroleum Industry (1946-1965)*.

CONCLUSIONS

SUPPLY AND DEMAND

This study has determined that a number of factors involving supply/demand, environmental and economic concerns have contributed to the shortfall of domestic refining capacity. It is important to realize that no single program or policy has caused nor will alleviate current and projected shortfall of domestic refining capacity. Any measures taken to attain short-term results must be cognizant of the effect of these measures upon long-term situations. Several of the more important factors which have an impact upon the refining situation and their implications are discussed in the following sections.

Product Demands Exceeding Capacity

The requirements for refining capacity are set by the demand for petroleum products, which is expected to grow at a rate of 5.7 percent per year from 1971 to 1975; 2.7 percent per year from 1976 to 1980; and, 3.0 percent per year from 1981 to 1985. At these growth rates, demand for petroleum products will be nearly double the demand for the 1971-1985 period, increasing from 15 million barrels per calendar day (MMB/CD) in 1970 to over 26 MMB/CD in 1985. The refining capacity necessary to satisfy 1985 demand will therefore exceed 25 MMB/CD. Operating capacity of U.S. refineries on January 1, 1973, was 13.2 MMB/CD, with about 2.5 MMB/CD of products being imported. Thus, if projected petroleum product requirements are to be met, it will be necessary to construct new refineries or expand existing refineries to add about 9 MMB/CD of capacity by 1985. The additional capacity will have to be built in the United States or come from existing or future offshore facilities in order to meet projected demand as shown in Figure 1. If these requirements were to be met solely from U.S. refineries with petroleum product imports completely eliminated, about 12 MMB/CD of new capacity will have to be constructed by 1985.

U.S. refining capacity was adequate to meet refined product demands until the 1960's. Since then, a shortfall in domestic refining capacity has developed, especially for residual fuel oil. Imports of such products have increased substantially, particularly into the East Coast. Until now, physical refining capacity has existed in the United States to meet the total demands for lighter fuel products--gasoline, jet fuels, etc. Now, however, demand for light products has also exceeded domestic capacity. By 1975, the total "shortfall" of domestic refining capacity is projected to be 25.9 percent of total refining capacity required or 4.8 MMB/CD.

The present shortfall of domestic refining capacity is the result of a series of emerging trends intensified by a surge in demand in 1972. For example, the current deficit of heavy fuel oil capacity developed over an extended period of time, while the shortfall in capacity to meet light product requirements is of more

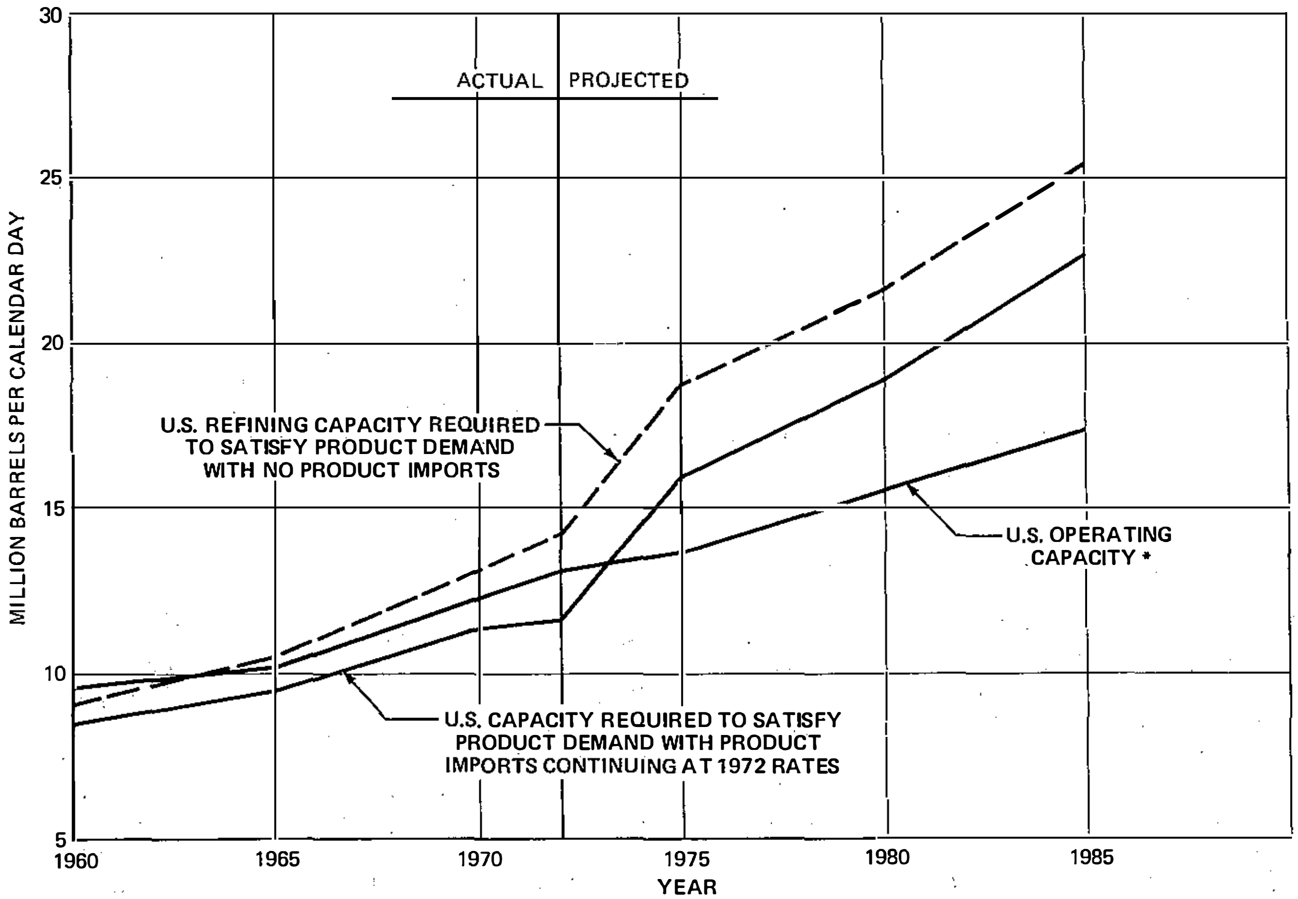

Figure 1. Total U.S. Operating Refining Capacity *Versus* Requirements--1960-1985.

recent development. It takes several years for new plans to become operational, and lead time must be considered an important element of future planning. Because of the necessary lead time to plan and build new capacity and because no large increments of new capacity are now in the construction stage, it has been necessary to modify import controls to permit an increase in product imports in order that projected demand can be met. While this assumes that sufficient petroleum products are available in world markets, the Committee has not evaluated world refining capacity to determine the validity of this assumption. However, it is felt that, if large increases in U.S. demand continue, world capacity may be outstripped by demand, much as U.S. capacity was in 1972.

Uncertainty Concerning Assurance of Supply and Quality of Crude Oil

The decline in exploration for and production of domestic crude oil has resulted in greater difficulties in obtaining assured crude supplies. This has had an inhibiting effect on the expansion of U.S. refineries. In 1975, crude oil and product imports are expected to be double the 3.4 MMB/D imported in 1970; imports in 1985 could be as high as 19.2 MMB/D, depending upon the degree of national commitment to domestic energy production.* Thus, domestic refineries are now compelled to rely increasingly upon foreign sources of crude supplies. In order to meet requirements--at least in the short term--the United States will also have to depend upon foreign refining capacity for increased amounts of product imports.

In addition to the uncertainty regarding long-term assurance of crude oil supply, the distinctive characteristics of the crude oil itself are important factors in the refining process. A given refinery cannot effectively process every type of crude oil. If a refinery processes a type of crude oil for which it was not designed, the effective throughput capacity of the refinery will in many cases be reduced substantially. Today there is shortage of both domestic and foreign low-sulfur crude oil, and this is expected to continue in the near future. Many domestic refineries are designed, both from a metallurgical and from a processing viewpoint, to accommodate only low-sulfur crude oil. High-sulfur crude oil--the type most generally available from foreign supply sources--cannot be exclusively processed in a domestic refinery designed for low-sulfur crude oil without the installation of additional facilities and/or extensive modification of existing facilities to prevent corrosive damage and to meet product specifications.

Increased Demand for Refined Petroleum Products and Petrochemical and Synthetic Natural Gas (SNG) Feedstocks

The demand for refined petroleum products could increase above projected requirements if demand is stimulated by such factors as the continuation of current shortages of natural gas, continuation of delays in bringing nuclear-fueled electricity generating capacity on-line, and a future decrease in the availability of environmentally and economically acceptable low-sulfur coal.

Although oil is not completely interchangeable with other fuels in existing equipment, it can supplement the needs in any energy consuming sector of our economy. In effect, it can act as the "swing" fuel. If gas finding rates are disappointingly low in the future, oil can be used to fill the need. The same concept holds true for oil as an alternate to nuclear power and coal when necessary and where applicable.

The required specifications for individual products are affecting both the type and the amount of capacity required. The increasing demand for low-sulfur residual fuel oils (0.3 weight-percent sulfur) requires the installation of extensive treating facilities. Not all crude oils can be processed utilizing existing technology to yield these fuels economically, and crudes which are naturally low in sulfur are in short supply in world markets. Motor gasoline, representing nearly 40 percent of total U.S. oil demand, is also sensitive to environmentally induced specification

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* NPC, *U.S. Energy Outlook--A Summary Report of the National Petroleum Council*, December 1972. Hereafter referred to as U.S. Energy Outlook Report.

changes. Emission control equipment on new automobiles is reducing fuel efficiency, thus increasing gasoline demand. While this in itself is increasing refinery capacity requirements, the need for unleaded gasoline for these new vehicles is also significantly increasing the amount of crude capacity required to produce a given volume of gasoline.

In the last few years, the domestic manufacture of petrochemicals has become closely related to domestic crude oil refining capacity. Supplies of domestic natural gas liquids, which are important petrochemical feedstocks, are declining, and petrochemical producers are having to turn more and more to refinery naphtha and gas oil. This shift in feedstock will result in a closer relationship between the refining and petrochemical industries as well as in increased need for integration of petrochemical and refining planning and operation.

The National Petroleum Council has projected petrochemical feedstocks to grow from less than 6 percent of total petroleum demand in 1970 to about 8 percent in 1985.* If refining capacity moves offshore, then petrochemical producers may have to use imports for their feedstock supplies, or move offshore with those refineries. Conversely, if refining capacity is kept onshore, feedstock supplies can be expected to be more readily available.

An additional demand factor which will affect both petrochemical and refining operations is the planned reforming of naphtha and other petroleum liquids into SNG. Feedstocks for SNG manufacture could approach 1 MMB/CD by 1985.

ENVIRONMENTAL CONCERNS

Americans are becoming aware of the potential conflict between energy requirements and environmental goals. Both high energy consumption rates and satisfactory maintenance of environmental standards are possible but only through dealing effectively with the total environmental, social and economic system.

The principal environmental factors which have had inhibiting influences on the expansion of domestic refinery capacity are discussed in the following sections.

Availability of Refinery Sites

Requirements relating to construction and operating permits and other environmental considerations have seriously limited and delayed site development for new plants. Environmental issues and restrictive emission requirements have delayed or actually prevented new refining construction. Of more concern than the difficulty

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* NPC, *U.S. Energy Outlook: An Initial Appraisal 1971-1985*, Volume Two, November 1971. Hereafter referred to as the Initial Appraisal.

of complying with these requirements are the instances where proposed refinery construction--after complete compliance with federal, state and local requirements--is halted by citizen group court actions.

Despite the rigorous standards for both water and air quality that refineries must meet now and in the future, resistance still exists in many areas of the country to constructing plants, even with appropriate environmental equipment. It is hoped that, as the public becomes more aware of the excellent pollution control performance of modern refineries, such resistance toward plant location will disappear.

Availability of Deepwater Port Facilities for Crude Oil Imports

While domestic reserves need to be developed to their fullest extent, a need will still exist for supplemental quantities of crude oil from other countries. The most efficient and economical method of transporting these requirements to refinery centers is through the use of very large crude carriers (VLCC's). Effective use of VLCC's--tankers having greater than 150,000 deadweight tons (DWT) displacement--will require the construction of deepwater ports located offshore, with pipelines delivering supplies from these superports to refineries.

Documented evidence shows that most spills from tankers occur during loading and unloading at ports now located on shorelines. Deepwater unloading terminals offer environmental advantages in that they would minimize such occurrences and effects of accidental spills on nearby shorelines by requiring less frequent ship movements and by allowing these movements to take place at more remote distances from land. Likewise, VLCC's with compartmented cargoes and highly trained crews, along with sophisticated new navigation equipment and safety developments, offer environmental advantages over smaller vessels.

Availability of Crude Oil

As mentioned earlier, basic to any refinery construction plans is the assurance of availability of suitable crude oil of known quality and assured stability of supply for a reasonable period of time. Environmental concerns have, at times, delayed the development of supplies of available or potentially available crude oil to refineries.

Perhaps the most important hinderance to refining construction is unreasonable interference with access to domestic crude oil resources after detailed studies have assessed the impact of environmental issues and demonstrated cost-benefit effectiveness. For example, reserves of crude oil on the North Slope of Alaska which were discovered in 1968 have been estimated to be over 10 billion barrels, a volume which is equivalent to about one-third of the known reserves of the lower 48 states. Billions of dollars of industry's capital have been rendered nonproductive by citizen group court actions and other delays associated with environmental concerns. These dormant reserves have not only drained funds from uses in other ventures, such as expanding refinery capacity, but have increased our Nation's dependence on imports with attendant penalties on national security and balance of trade. The Nation cannot afford to allow these resources to remain unused indefinitely. Even under the most optimistic predictions, it will be several years before supplies of crude oil can be moved from the Alaskan North Slope to domestic refineries.

The potential for discovery of large quantities of crude oil and natural gas exists in offshore waters surrounding our continent. However, many areas of the continental shelf of the United States remain undeveloped or underdeveloped because of environmental concerns.

ECONOMIC FACTORS

Important changes are taking place in the economic environment in which refineries find themselves. Crude oil is being supplied in increasing amounts from foreign sources, and prices of foreign crude oil landed in the United States are rising sharply, exceeding delivered domestic prices in some cases. Refining facilities are becoming more complex in both design and materials requirements and are increasingly more expensive per barrel of capacity.

The principal economic factors affecting the expansion of domestic refining capacity are discussed in the following sections.

The Economic Outlook for New Refining Investment Has Become Uncertain

Refiners are having to compete for funds in capital markets at a time when investment dollars are becoming tight and are being attracted to those investments with a rate of return more commensurate with future risk and stability. Rates of return on refining investment must be adequate if financing is to be available for construction of new domestic refining capacity. Current economic conditions and the lack of encompassing U.S. policies on energy matters has made the outlook for new investments in new refineries quite uncertain.

Illustrative economic comparisons have been prepared concerning the cost of operating a refinery located in perimeter areas (Caribbean or eastern Canada) to the cost of the same refinery located in either Petroleum Administration for Defense (PAD) District I (U.S. East Coast) or PAD District III (U.S. Gulf Coast).* In all cases, the refineries were operated on the same Middle East crude.

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* *These illustrative economic comparisons were prepared prior to the issuance of the President's Energy Message to Congress of April 18, 1973, and do not take into account the oil import proclamation contained therein.*

They were operated to produce a product mix comparable to the projected growth in District I product demand between 1970 and 1985, with the products ultimately delivered to the same market locations in District I. These costs do not include any cost associated with acquiring the crude oil import quota but do include 1972 level import duties. They assume an application of current statutory income tax rates--zero for the Caribbean example, 48 percent for the United States and 49 percent for an eastern Canada refinery.

While these studies are only illustrative examples, they indicate that a refinery located in District III can expect average product costs which are on the order of $0.60 per barrel higher than the refinery located in the Caribbean. Assuming that such a refinery is built in District I, the economic advantage of the Caribbean refinery is reduced to approximately $0.40 per barrel. On the other hand, in eastern Canada, where the tax rates are comparable to those in the United States, the economic advantage tends to disappear--except in those instances where specific tax advantages and other benefits have been granted.

Recent Product Price Controls Will Lead to Increasing Supply Shortages

If the United States continues to impose price controls--direct or indirect--on petroleum and/or refined petroleum products in order to stabilize the economy, the full cost and financial risk of providing new supplies of petroleum products must be recognized, including higher costs of imported supplies. If they are not, refinery expansion will be discouraged, and shortages of domestically refined petroleum products will occur. To the extent available, products would have to be imported from world markets at prices which are not subject to U.S. price controls. This, in turn, could drive market prices for imported products landed in the United States higher than those of products refined domestically, a consequence currently being experienced.

Restrictive and Inflexible Import Regulations*

The relative inflexibility of the crude oil quota system, coupled with the decline in domestic crude oil production, has restricted the development of new refining capacity. While it is true that total U.S. import quotas would increase by the amount of new capacity built, there has been no direct mechanism to pro-

* *The President, in his energy message to Congress of April 18, 1973, has removed by proclamation all existing tariffs on imported crude oil and products and has suspended direct control over the quantity of crude oil and refined products which can be imported. In place of the control system, the President has initiated a license fee system. The President stated that, to encourage domestic refinery construction, crude oil in amounts up to three-fourths of new refining capacity may be imported for a period of 5 years without being subject to any fees.*

vide an existing refiner or a potential refiner with the necessary access to foreign crude oil supplies necessary to the operation of new refinery capacity in the United States. Limited and inadequate starter allocations were the only existing provisions for granting crude access for new refining capacity. The difficulties and costs of acquiring imported supplies from others were discouraging factors in refiners' decisions regarding new capacity construction.

The exemption of certain products from formal quota controls, however, has led to the construction of sizable refining capacity outside the United States. The ability to import these products into the United States, the ability to acquire long-term foreign crude oil supplies, and the economic advantage of offshore refining favor the buildup of refining capacity in these perimeter areas.

Requirements for Transportation and Storage Facilities

Increased requirements for petroleum will require the expansion of transportation and operational storage facilities. Most of the incremental crude oil supplies will be imported from the Middle East and Africa. For such long distances and large quantities, the most economical and environmentally safe system for receiving such oil is by direct shipment to the refining center utilizing VLCC's and properly disigned deepwater crude unloading terminals. Considering the lowest cost logistical system for waterborne imports of crude oil, the capital required for the 1971-1985 period is substantial. Estimated investments for deepwater port facilities and for foreign construction of new 250,000 DWT vessels range from $14 to $16 billion. Total capital requirements may be higher depending on the extent to which U.S. shipyards must be used for vessel construction. Additionally, cargo preference legislation which would require the use of American flag vessels on direct shipments to the United States would substantially increase the transportation charge per barrel of delivered oil. Because of these increased costs, such legislation would act as a disincentive in the construction of U.S. refining capacity.

Storage requirements will also rise as imports increase. Domestic refineries running on domestic crude oil production need very little crude storage. With future receipts arriving in VLCC's, refiners will need facilities to store their large cargoes (almost 2 MMB can be carried in a 250,000 DWT tanker) and to maintain a working inventory to ensure continuous operation in the event that shipments are delayed.

U.S. ENERGY POLICY OBJECTIVES

The National Petroleum Council recognizes that the primary energy industries, in cooperation with the government, are responsible for meeting the energy needs of American society. This responsibility must be met while assuring free consumer choice at the lowest costs consistent with adequacy of long-term supply, preservation of the environment, and promotion of efficient use of energy and energy conservation. The impact of the effects of energy availability and costs on economic welfare and progress and, more importantly, the need to preserve national security underline the significance of this responsibility.

The NPC's U.S. Energy Outlook Report includes recommendations for a U.S. energy policy. This study reiterates some of those recommendations since petroleum refining is an integral part of the energy industries and, as such, is affected by overall U.S. energy policies. This report also contains additional recommendations which are more specifically related to domestic petroleum refining operations.

These recommendations are made with the belief that a healthy and viable domestic petroleum industry, in all its functional operations, is essential to the economic well-being and the national security of the United States. Increased "exportation" of petroleum refining capacity outside the United States results in the loss of domestic financial and manpower employment opportunities; reduces taxation revenue to federal, state and local governments; results in larger deficits in the U.S. balance of trade and payments; and, adversely affects other types of manufacturing.

The United States Must Have a National Sense of Purpose to Solve the Energy Problems

A long-term national sense of purpose must evolve to meet the social and economic issues related to energy problems similar to the national dedication to environmental conservation and full employment. It is this dedication and the cooperation among government, industry and private citizens that must be expanded if the issues relative to locating and siting future refining facilities are to be resolved. Environmental issues and aesthetic considerations must be balanced against the socioeconomic benefits of developing adequate sites for refining facilities to meet public requirements. The need to provide our Nation with adequate energy at a reasonable cost is a matter of such vital concern that it will necessitate rational resolution of the inconsistencies and conflicts emerging in federal, state and local planning involved in siting and other considerations.

The Federal Government Should Encourage an Economic and Fiscal Climate Conducive to Energy Development

It has been projected that meeting U.S. energy requirements during the 1971-1985 period will require capital outlays of between $450 and $550 billion. For such vast sums of money to be generated by U.S. energy suppliers, several conditions must exist:

- *Competition:* Competitive markets are a particularly effective mechanism for determining price levels necessary to balance energy demand and supply. The complex operation of market forces will best serve consumers and the national interest by providing energy in amounts needed and in forms preferred for environmental reasons. Market forces, if unfettered, would promote efficient use of energy and allocate resources among energy activities on an economical basis.

  Vigorous competition requires unrestricted entry into the various energy fuels markets, subject to applicable antitrust laws. Competition is stimulated when a supplier of one fuel can provide additional capital investment, technology and management skill for the development of other fuels.

- *Free Market Prices:* A favorable economic climate enabling companies to generate internal sources of capital, as well as to compete in capital markets, is essential to the long-term development of energy resources. Profitability is essential to free enterprise, and prices must be permitted to reflect costs and provide an adequate return on invested capital.

  Because of the deep and inseparable relationship between domestic refining and the world petroleum industry, it is very unlikely that the problem of new refining capacity will be met without restoring the free play of an open domestic market. In recent years, product prices have been inadequate to provide sufficient return on new investments commensurate with the risks involved. Any external forces such as price controls which hold prices below market clearing levels will continue the trend of insufficient returns of the industry. Flexibility to adjust prices based on market supply and demand forces within the United States should be sufficient to permit realization of an adequate return on present and future investment.

- *Fiscal Policies:* Fiscal policies, such as the investment tax credit and accelerated depreciation rates, should be utilized to foster the availability of capital requisite for the construction of new refineries. Such policies should be designed to encourage growth of domestic refining, petrochemical and SNG facilities.

  Whatever policies are adopted should be clear and firm. If investors believe that government inducements to build onshore refineries are temporary, the economic attractiveness of onshore refineries will be weakened. For example, turning the investment tax credit on and off to control the economy is not an effective inducement to refinery construction.

Import Policies Should Be Designed to Encourage the Growth of Domestic Refining Capacity*

Increasing product imports at the expense of domestic refining capacity would place the United States in a position of having to depend on foreign sources for a growing part of its crude oil supply. It would also, to an increasing degree, result in U.S. dependence on foreign processing capacity. This would appear to be contrary to U.S. national security and national defense as defined by Section 232 of the Trade Expansion Act of 1962.

In order to be effective, any system of import controls, whether quota restrictions or variations thereof, should at the very least consider:

- More favorable provisions for importation of crude oil than refined products
- Provisions to ensure a market for all domestic crude production
- Policies that provide the domestic refiner assurances of an adequate and long-term supply of crude oil from domestic as well as foreign sources and, in so doing, assure maximum utilization of existing refining capacity
- Incentives to offset the disadvantages faced by domestic refiners when manufacturing products currently exempt from formal quota control
- Provision for maintenance of the U.S. petrochemical industry's competitive position in world markets
- Consistency and stability in order to provide refiners the basis for establishing long-term planning objectives
- Emergency reserve oil storage capability†
- Compatibility with overall objectives of national energy.

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* *The President, in his energy message to Congress of April 18, 1973, has removed by proclamation all existing tariffs on imported crude oil and products and has suspended direct control over the quantity of crude oil and refined products which can be imported. In place of the control system, the President has initiated a license fee system. The President stated that, to encourage domestic refinery construction, crude oil in amounts up to three-fourths of new refining capacity may be imported from a period of 5 years without being subject to any fees.*

† An in-depth analysis of this subject is addressed by the NPC's Committee on Emergency Preparedness.

The Construction of Modern Transportation Facilities Should Be Encouraged

Unloading facilities for VLCC's, built as close as practical to the coastal refining centers, result in the lowest cost transportation system. This would ideally place the unloading facility just offshore, with onshore distribution made by pipeline. The site must have sufficiently deep water, uncongested approaches from the sea and minimum potential for environmental disruption. With the equipment possible under the existing technology, near pollution-free operation is attainable. In addition, if it is not at an existing terminal or refinery, the site should have an onshore area suitable for oil storage facilities and access to a sufficient infrastructure for support of the facility. Specific site locations for deepwater terminals are currently under study by government and industry groups. Because offshore refineries can take advantage of the lower unit costs associated with VLCC's and deepwater ports, the lack of such facilities has in the past and will continue in the future to act as a disincentive to the construction of domestic refining capacity.

An additional cost to a domestic refiner of foreign crude oil would be incurred by legislation requiring receipt in American flag tankers. Any benefits of such legislation to the economy must be weighed carefully against the added costs incurred.

A Rational Balance Must Be Achieved Between Environmental Goals and Energy Requirements

The goals of a cleaner environment and increased domestic refining capacity are not incompatible. Both are important to the Nation's well-being, and both can be accommodated. It is not necessary to export refining capacity to maintain a reasonably clean environment.

Recent experience has shown that many of the present refineries can be expanded and the necessary new refineries can be built while achieving a satisfactorily clean environment. In this effort to expand our energy supply, it is essential that the emission standards imposed be realistic. As zero emission levels are approached, costs and operating problems tend to become excessive, often without measurable benefit to the environment and often with attendant waste of resources.

Economically viable refineries have certain requirements for their location. These include land space, access to raw material supply, product distribution systems and adequate labor. While local communities should be concerned with environmental protection, they must recognize the Nation's need for essential plants and facilities. Regulations regarding the offical sanction of refinery sites should be revised to speed up the approval process while maintaining proper environmental protection for the communities involved.

The cost benefit of the following features of environmental improvement must be weighed carefully. In particular, it should be noted that, as environmental standards are made more restrictive, costs and the use of irreplaceable resources go up at an increasing rate.

- Consumption of petroleum products will be increased by the substitution of low-sulfur residual fuel oil, liquefied petroleum gas (LPG) and distillate fuels for natural gas and nonpetroleum fuels (such as coal) as well as by the use of less efficient automobile engines.
- Refining costs and crude oil requirements will be increased substantially in order that fuels meet Environmental Protection Agency (EPA) proposed lead regulations and the required auto emission standards established by the 1970 amendments to the Clean Air Act.
- Transportation costs will be increased by banning deepwater port construction and construction of refineries in the most economical locations.
- The magnitude of expenditures for environmental needs are significant as even large refineries (over 100 MB/CD) report costs in excess of 10 percent of all refinery investment to meet environmental regulations.

Both Government and Industry Should Continue to Promote Energy Conservation and Efficiency of Energy Use in Order to Eliminate Waste of Our Resources

Energy producers and the U.S. Government should exert positive leadership in advocating energy conservation measures. However, forced reductions in energy consumption should be employed only on an emergency basis.

A reduction in future petroleum requirements can be achieved if the Nation takes timely and vigorous steps to use petroleum products and natural gas more prudently than it has in the past. To the extent that conservation results in reduced consumption, the strain on domestic refining capacity will be lessened. Additionally, the burden of either crude oil or product imports will be reduced.

Federal Policies Should Encourage Domestic Crude Oil and Natural Gas Production and Development of Synthetic Fuels

Assurance and stability of crude oil supply is necessary to plans and programs for expanding or building refining facilities.

Increased availability of domestic crude oil supply offers the greatest assurance against future supply interruptions and provides a stable economic climate which would attract and encourage private investment capital for the construction of refining facilities. Utilization of the Nation's vast resources of coal and oil shale to manufacture synthetic oil and gas for fuels and feedstocks will also have a stabilizing effect on the assurance of supply and the stability of the economic climate.

Similarly, additional domestic supplies of natural gas should be encouraged in order to decrease the burden placed on refining capacity to manufacture those additional products which are now required due to current shortages of natural gas.

The artificially low price for gas established by the Federal Power Commission (FPC) has influenced the consumer in both choice of energy source and the amount used. The competitive price established for alternate fuels, such as coal, fuel oils and heating oils, has affected production and the economics of producing these alternate sources of energy. Rapidly increasing consumer demands for natural gas--the "cheap" fuel--coupled with insufficient supplies have contibuted to the overall energy shortage.

The Federal Government Should Coordinate the Many Competing and Conflicting Agencies Dealing with Energy

Much of the confusion and delay that now plagues energy suppliers stems from conflicts among government agencies. All too often one agency may encourage an action while another agency prohibits it. Consistent guidelines and stability of policy on energy matters are necessary to ensure that the Nation's vital needs are met.

Part Two
The Report of the Committee

Chapter One

TRENDS IN PETROLEUM REFINING REQUIREMENTS, CAPACITY AND CAPABILITIES

INTRODUCTION

This report defines "refining capacity" as the capacity to process crude oil, i.e., crude oil throughput for the purpose of manufacturing refined products. The processing of crude oil to finished products requires many varied steps. These steps or unit processes are determined primarily by two considerations: (1) the volume and characteristics of crude oil to be processed and (2) consumer requirements for individual refined products. Each refinery in the United States processes a mixture of crude oils different from that being processed in any other refinery; has a different configuration of processing units to convert the crude oil to refined products; and, produces a different mixture of refined products. Therefore, the reported refining capacity is based on a certain type of crude oil being processed and the manufacture of a premised mixture of refined products having defined characteristics or meeting certain specified requirements.

A change in the characteristics of crude oil available to a refinery will affect the capacity of the refinery to process crude oil. Many refineries are designed to process low-sulfur crude oils, if significant volumes of high-sulfur crude oil were processed instead, the refinery would soon become inoperable. (See Appendix C for a brief explanation of basic information and interrelationships concerning crude oils, refining operations and refined products.)

In order to develop data for a study of domestic refining capacity, it was considered important to have not only historical data but also data concerning the current status and future plans for additional refining capacity. For this purpose, the NPC sent a survey questionnaire to all companies operating refineries in the United States. The respondents represented over 90 percent of U.S. capacity. Key conclusions and data derived from this questionnaire are used throughout this volume. It should be noted that the survey data reflect present and future plans as of the fall of 1972. The results serve as a background for evaluating the effects of economic and governmental changes.

HISTORICAL AND PROJECTED PRODUCT DEMANDS

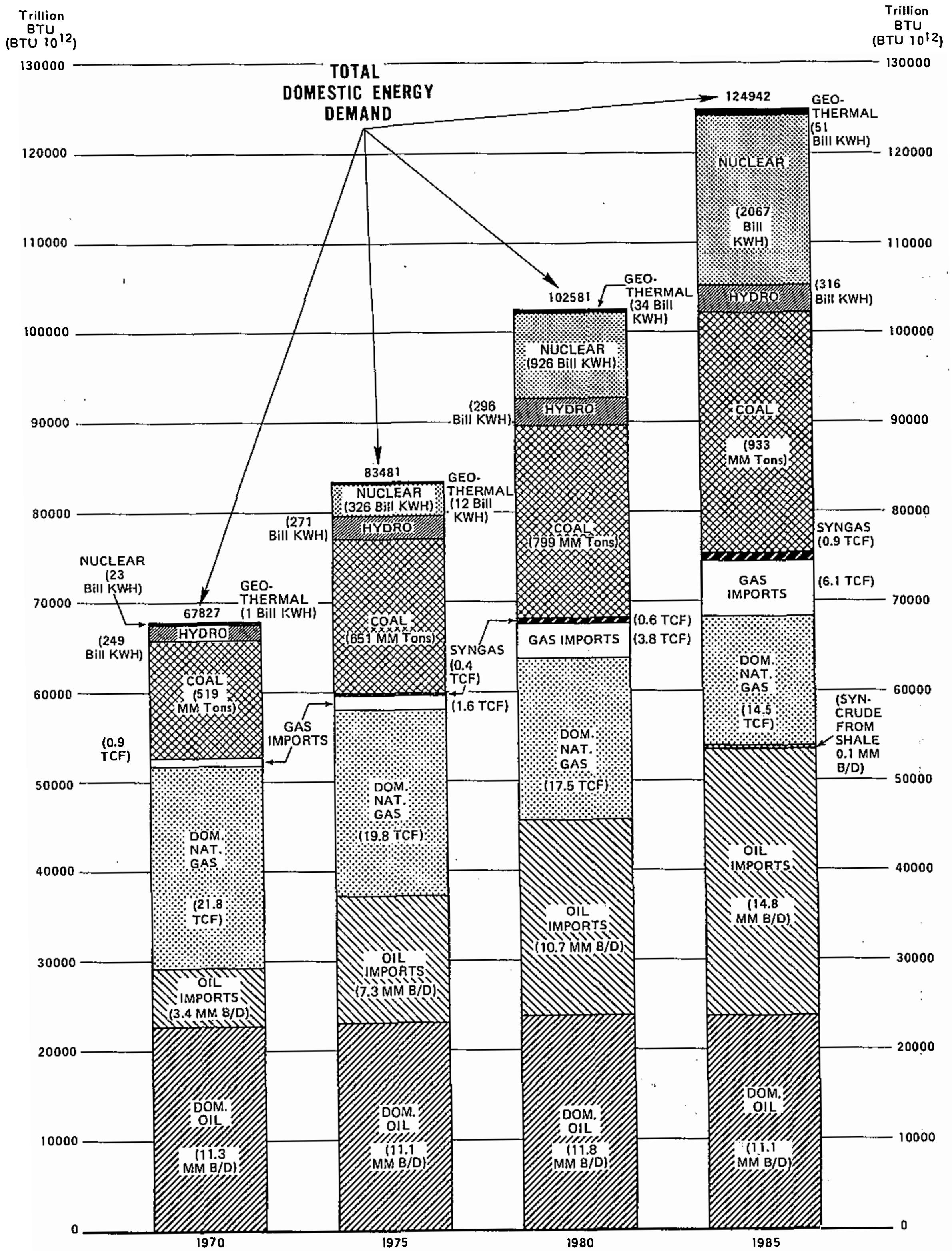
The requirements for refining capacity are related to and dependent upon petroleum product demands. In the NPC's Initial Appraisal, a comprehensive long-term projection of energy demands in the United States through 1985 was presented. An assessment was also made in that report of total U.S. energy consumption by market sectors. The various fuel subcommittees (oil, gas, coal, nuclear, etc.) applied their respective judgments in deciding what factors would affect demands for the particular fuel examined and took into account the probable supply of other fuels. The resulting U.S. energy balance for the Initial Appraisal is shown in Figure 2. From this balance, final projections of future demand for refined products were made.

Examination of Figure 2 shows that the demand for energy is expected to almost double during the 1971-1985 period. In order to meet these energy requirements, a tremendous investment program is required to find and produce more oil and gas; to build the refineries that are needed to process the additional volumes; and, at the same time, to expand the distribution systems that will deliver the additional products to the consumer. Other energy suppliers also have to expand and they will require additional funds to develop new coal and uranium mines, build nuclear and conventional power stations, and develop technology to commercialize new sources of energy (e.g., shale oil, solar, geothermal, etc.). Substantial investments will also be required so that existing as well as new facilities can meet environmental standards.

The detailed oil demand projections included in the energy balance were used as a starting point. In view of oil demands increasing beyond all projections in 1972 and the expectation for another large increase in 1973, the Committee believed the near-term demand level in the Initial Appraisal to be low. Therefore, the projection for the year 1975 was revised. It was believed, however, that the factors limiting demand growth assumed in the Initial Appraisal would be at work in 1980 and 1985, and the projections for these years were not changed.

The historical growth rate for refined products shows an average increase of 3.2 percent per year from 1961 to 1965, and an average rate of 5.1 percent per year from 1966 to 1970. Future demand for petroleum products is projected to grow at a rate of 5.7 percent per year from 1971 to 1975; 2.7 percent per year from 1976 to 1980; and, 3.0 percent per year for the period from 1981 to 1985. The historical data and the projected growth rates are shown in Table 1.

The historical demand for petroleum products and the Committee's projection of future demand for these products are plotted in Figure 3. Even though the projected demand for refined products for the years 1980 and 1985 were not changed, it must be realized that there are many factors which can alter future demands for products. Already, environmental concern over pollution from high-sulfur fuels has reduced or eliminated the use of traditional fuels (i.e., coal and high-sulfur residual oils) in many areas. Since reserves of natural gas and supplies of low-sulfur residual oils are insufficient to fill the void, many industrial consumers have had to switch to distillate fuels. This situation, plus the swing by big consumers on interruptible gas service to the use of propane, butane, or distillates, further compounds the problem of projecting demand.



Source: NPC, *U.S. Energy Outlook: An Initial Appraisal 1971-1985*, Volume One (July 1971), p.15.

Figure 2. U.S. Energy Balance--Initial Appraisal.

TABLE 1

TOTAL U.S. DEMAND FOR REFINED PETROLEUM PRODUCTS—1960-1985

	Total U.S. Demand* (MMB/CD)	Average Annual Growth over Previous Period %	MMB/CD
1960	10.0	—	—
1965	11.7	3.2	0.32
1970	15.0	5.1	0.66
1975	19.8	5.7	0.96
1980	22.6	2.7	0.54
1985	26.2	3.0	0.73
1970-1985 Average		3.8	0.77

* Includes adjustments of Figure 1 data for exports and more recent 1975 projections.

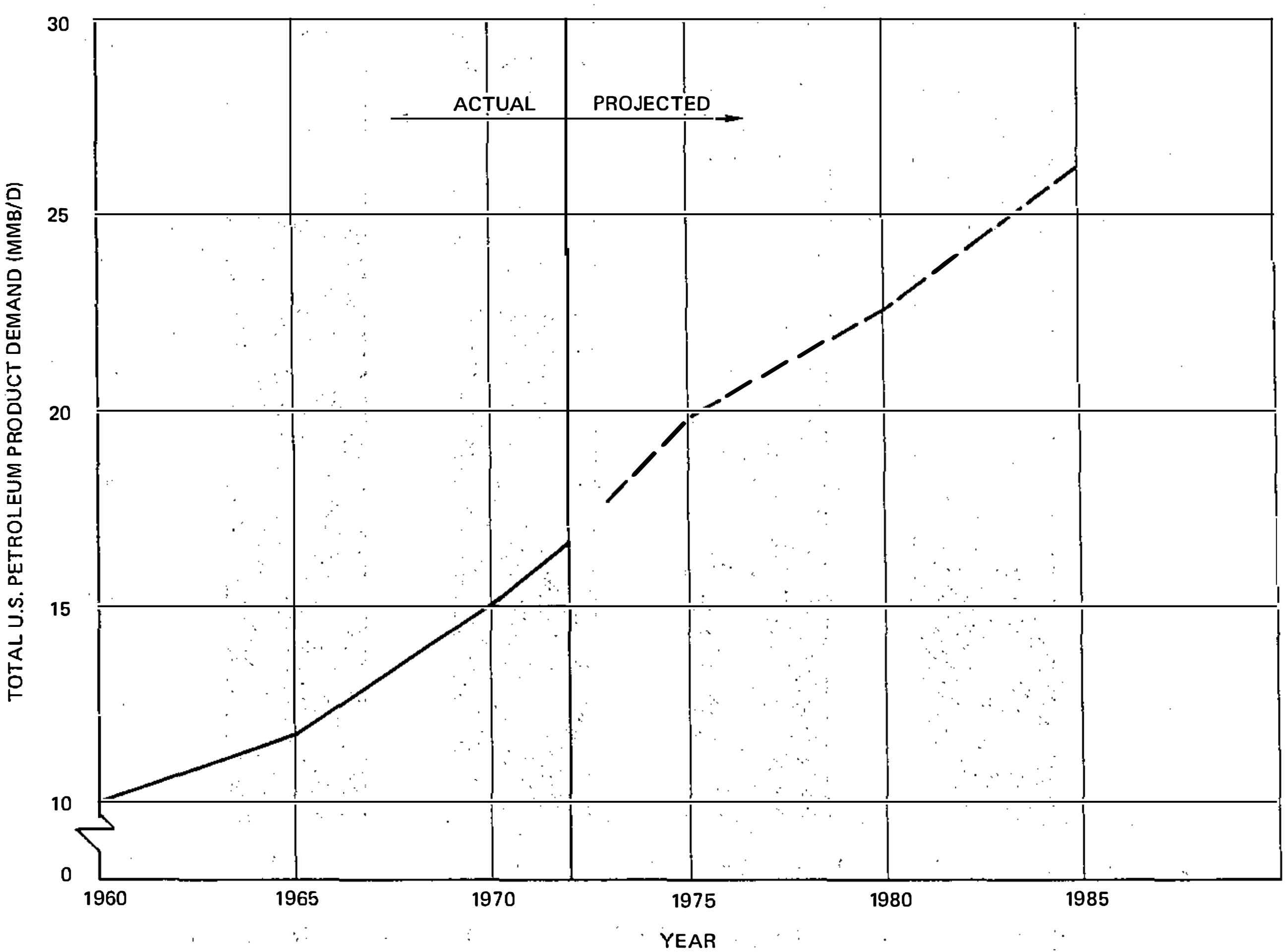


Figure 3. Total U.S. Demand for Refined Products--1960-1985.

HISTORICAL AND PROJECTED DOMESTIC REFINING CAPACITY

In order to properly evaluate the possible future trends in domestic refining capacity, it is desirable to review the historical patterns. As detailed in Appendix D, U.S. petroleum refining operating capacity as reported by the Bureau of Mines increased at a compounded annual rate of 2.9 percent during the 10 year period beginning January 1, 1962.

During this 10 year period, U.S. refining operating capacity was increased 3,241 MB/CD, or 33.1 percent, from a 9,794 MB/CD level to 13,035 MB/CD at the end of 1971. This net increase was accomplished by the construction of 5,386 MB/CD of additional capacity (equivalent to a 4.5 percent compounded annual rate of increase) and the abandonment of 2,145 MB/CD.

Of the 5,386 MB/CD of total additions, only 1,213 MB/CD, or 22.5 percent, represented new grassroots refineries. The remaining 4,173 MB/CD, or 77.5 percent, consisted of additions to the capacity of existing plants. The 2,145 MB/CD of capacity declines resulted from the partial or total shutdown of 73 refineries having a total capacity of 573 MB/CD (26.7 percent of decline); the loss of 628 MB/CD (29.3 percent of decline) through consolidations of facilities; and, 943 MB/CD (44.0 percent of decline) of capacity declines and shutdowns for which no reason was specified to the Bureau of Mines.

In spite of the addition of 38 grassroots refineries between 1962 and 1971, the number of operating refineries in the United States declined from 287 to 253, or 11.8 percent. Reflecting the increased capacity and the reduced number of operating plants, the average operating capacity of all U.S. refineries increased from 34,125 B/CD to 51,521 B/CD--an increase of 17,396 B/CD, or 51.0 percent.

Over 58 percent of the increase in U.S. refining capacity occurred in PAD District III where operating capacity increased from 3,562 MB/CD to 5,463 MB/CD. Figure 4 shows a map of the five Petroleum Administration for Defense (PAD) Districts. During the 10 year period, District III increased its share of U.S. refining capacity from 36.4 percent to 41.9 percent. Although 16 grassroots refineries were built in District III during the period, the number of operating plants declined from 86 to 82 as 20 refineries were shut down. Overall, District III operating capacity increased at a 4.34 percent compounded annual rate.

District V was the only other PAD District with refining operating capacity growing faster than the national average and was the only district showing a net gain in the number of operating refineries--increasing from 44 in 1962 to 45 in 1971. District V operating capacity increased from 1,513 MB/CD to 2,151 MB/CD--a net gain of 638 MB/CD, or 42 percent, representing a 3.6 percent compounded annual rate of increase.

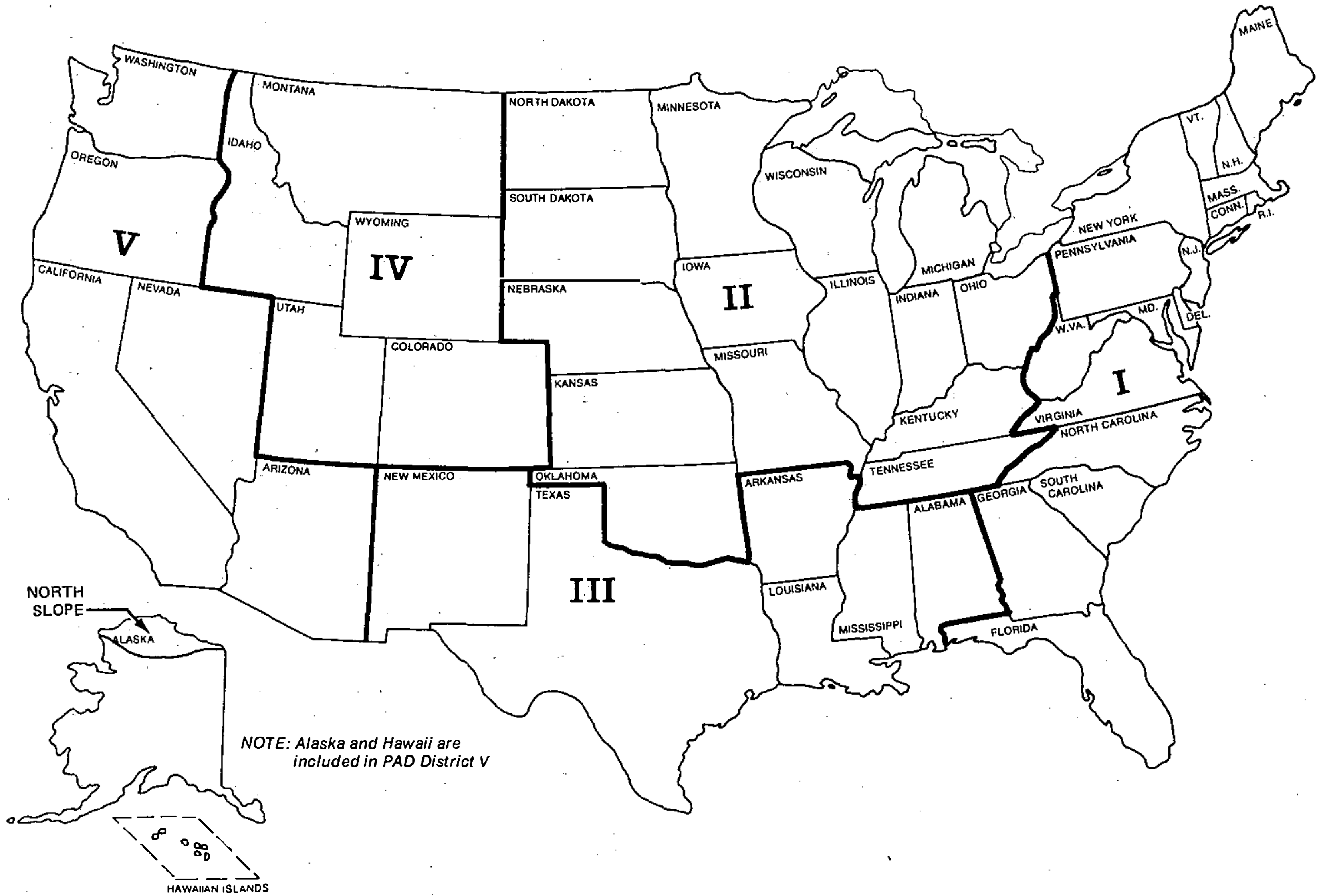


Figure 4. Petroleum Administration for Defense (PAD) Districts.

On the other end of the spectrum, refining capacity declined by 49 MB/CD, or 3.1 percent, in PAD District I--from 1,578 MB/CD in 1962 to 1,529 MB/CD in 1971--as no new grassroots plants were constructed and the number of operating plants declined from 35 to 30. By December 31, 1971, the share of U.S. refining operating capacity located in PAD District I had declined to 11.7 percent from 16.1 percent in 1962.

District II witnessed the greatest number of plant closings as the number of operating plants dropped from 92 to 70--a net decline of 22, in spite of 4 grassroots additions. District II capacity increased by 687 MB/CD from 2,783 MB/CD in 1962 to 3,470 MB/CD in 1971, representing a net compounded annual rate of increase of 2.2 percent.

District IV operating capacity increased from 357 MB/CD to 423 MB/CD--a net increase of 66 MB/CD equivalent to a 1.7 percent compounded annual rate of increase. District IV had a net loss of 4 plants, and at the end of 1971 the average refinery had an operating capacity of 16,256 B/CD.

PRESENT REFINERY CAPACITY AND CONDITION

In order to determine the present operating capacity, condition and planned expansions of the Nation's refineries and associated facilities, a questionnaire was sent by the National Petroleum Council to all petroleum companies operating refineries in the United States.

Responding to this questionnaire were 92 companies operating 186 refineries with a combined operating capacity of 12.3 MMB/CD as of January 1, 1973. Not responding to the questionnaire were 72 companies operating 73 refineries with an estimated operating capacity of slightly under 1.0 MMB/CD. Thus, as of January 1, 1973, the Nation had an indicated 13.2 MMB/CD of operating refinery capacity.

The condition of the refinery capacity can be described in qualitative terms with respect to various parameters:

- A refinery must be in relatively good mechanical and physical condition to ensure safe and orderly operation.

- Long-term life from a physical or mechanical standpoint is dependent on the continued expenditure of money for repair and replacement of equipment. Type of equipment and relative severity of operation have more of an effect on maintenance expenditures than does equipment age.

- Probably the most important considerations with respect to refinery condition are obsolescence due to uneconomic size, poor logistics, depletion of normal crude supply source and economic feasibility of meeting environmental plant and product requirements. The magnitude of expenditures for environmental needs are significant as even large refineries (over 100 MB/CD) report costs exceeding 10 percent of all refinery investment to meet environmental regulations.

The condition of the Nation's operating refineries is difficult to quantify. Even the average age of the Nation's refineries cannot be determined since the typical refinery has experienced numerous modifications and expansions over its operating life. Comparisons between Bureau of Mines and NPC questionnaire data indicate that only minor changes in total refinery operating capacity occurred in 1972. Based on historical performance, however, it is reasonable to expect that, in the future, about 2 percent of the Nation's refining capacity (or about 270 MB/CD, based on 1972 operating levels) will be abandoned each year. These shutdowns reflect obsolescence due to a combination of logistical, technological, environmental and economic considerations. The fact that little or no operating capacity was reported to be shut down during 1972 probably reflects the current and growing shortage of U.S. refining capacity, and there may be a temporary deviation from the historical abandonment trend. It should, however, also be pointed out that those refineries not responding to the survey were generally smaller. Historically, small refineries have had the highest abandonment rate--the average size of shutdowns during the 10 year period beginning January 1, 1962, being under 30 MB/CD.

Abandoning capacity is dependent in part upon operating economics and the requirement for additional capital to modernize the refining facilities for continuing operation. Significant sums of money will be required over the next 6 years in order that the Nation's present refineries may meet existing and proposed environmental regulations. As reported by the NPC survey, these costs are expected to total $3.3 billion (1970 dollars) for the 12.3 MMB/CD of operating capacity responding to the questionnaire. This is equivalent to an expenditure of $266 per daily barrel of capacity, of which $112 will be required for lead removal, $54 for control of refinery water effluent, $89 for control of refinery ambient air and $11 for control of refining noise and light.

Applying these factors to the Nation's total refining capacity of approximately 13.2 MMB/CD, one might reasonably project that the current condition of the Nation's refineries is such that $3.5 billion will have to be spent in order to meet environmental regulations. These environmental expenditures which will be required over the next 6 years are in addition to substantial expenditures already made. For perspective, $3.5 billion is equivalent to the expenditures required to construct 1.6 MMB/CD of additional refinery capacity based on a 1970 dollar refinery construction cost of $2,200 per daily barrel of capacity.* The condition of the Nation's

* The actual capital required for new refining capacity can vary between $1,500 and $2,500 per daily barrel (in 1970 dollars) depending upon the refinery size, the characteristics of the crude oil to be processed, the products to be manufactured and the specifications of the products.

refineries is such that in order to maintain current operating levels of 13.2 MMB/CD, expenditures of some $1.1 billion per year (equivalent to the cost of adding some 500 MB/CD of new capacity each year) will be required to offset abandonments and to meet environmental requirements.

An additional factor which leads to a reduction of capacity is the type of crude oil processed. If a refinery is forced to process certain types of crude oil for which it was not designed, its effective throughput capacity will, in many cases, be reduced substantially (see Appendix C). For example, a refinery designed to process a crude oil with a high gravity cannot process equivalent volumes of low-gravity crude oil. Domestic and foreign low-sulfur crude oils are in short supply, and many refineries are designed to process only this type of crude oil, both from a metallurgical and from a processing viewpoint. High-sulfur crude oils, the type generally available from foreign supply sources, cannot be processed in a refinery designed for low-sulfur crudes without the installation of additional facilities and/or extensive modification of existing facilities to prevent corrosive damage and to meet product specifications.

HISTORICAL TRENDS IN REFINERY PROCESSES*

A survey of process unit capacities of U.S. refineries shows how the need for certain processes has increased or decreased during the last 10 years. The changes are due to many factors--each refinery has its own particular problems and each section of the country has different product demands. Still, the composite picture displayed on Tables 2 and 3 clearly shows certain trends.

Crude Oil Distillation Capacity

Crude oil distillation capacity in the United States was 13.1 MMB/CD as of January 1, 1972, and has increased by over 3 MMB/CD since the end of 1961. This is a growth rate of approximately 2.6 percent per year, or a total increase of 30 percent in 10 years. Since the late 1960's, however, domestic refining capacity has shown a marked reduction in rate of growth. In 1971, the gain was only 406 MB/CD, or 3.2 percent, compared to increases of about 550 MB/CD, or 4.7 percent, in each of the previous 2 years. This reduction was more evident in 1972 since there was only one new grass-

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* Because Bureau of Mines does not report detailed refinery process data, the *Oil and Gas Journal* data are utilized in this section. Total capacity data will differ slightly for that of the Bureau of Mines used elsewhere in this report. Additional discussion of the changes in the technology of the refinery processes discussed in this section can be found in the companion volume, *Factors Affecting U.S. Petroleum Refining, Impact of New Technology*, September 1973.

TABLE 2

SURVEY OF OPERATING REFINERIES IN THE UNITED STATES – 1962-1972

		Operating Refining Capacity		Charge Capacity (MMB/SD)								Production Capacity (MMB/SD)				
						Catalytic Cracking										
Date	Number Plants	(MMB/CD)	(MMB/SD)	Vacuum Distillation	Thermal Operation	Fresh Feed	Recycle	Catalytic Reforming	Catalytic Hydro-cracking	Catalytic Hydro-refining	Catalytic Hydro-treating	Alkyla-tion	Catalytic Polymeriza-tion*	Lube	Asphalt	Coke (MT/SD)
1/1/62	299	10.01	10.59	3.67	1.81	3.75	1.47	2.02	–	–	2.37	0.46	0.14	0.21	0.49	18.90
1/1/63	293	9.92	10.46	3.58	1.75	3.89	1.55	1.99	–	–	2.54	0.49	0.13	0.20	0.49	19.20
1/1/64	288	10.18	10.72	3.75	1.72	3.99	1.62	2.05	–	–	2.75	0.50	0.13	0.20	0.51	20.94
1/1/65	275	10.25	10.76	3.76	1.64	3.99	1.57	2.06	–	–	2.93	0.53	0.13	0.21	0.54	21.14
1/1/66	265	10.25	10.75	3.76	1.69	3.96	1.53	2.09	–	–	3.10	0.55	0.12	0.21	0.53	23.03
1/1/67	261	10.45	10.95	3.89	1.64	3.95	1.65	2.19	–	–	3.35	0.60	0.11	0.21	0.54	25.00
1/1/68	269	11.14	11.66	4.08	1.66	4.18	1.60	2.38	0.41	–	3.66	0.65	0.10	0.21	0.53	28.43
1/1/69	263	11.57	12.08	4.12	1.60	4.25	1.55	2.54	0.50	0.55	3.27	0.67	+ 0.25	0.20	0.57	29.43
1/1/70	262	12.15	12.65	4.55	1.64	4.37	1.49	2.78	0.60	0.54	3.51	0.75	0.29	0.21	0.58	35.49
1/1/71	253	12.68	13.28	4.74	1.56	4.51	1.46	2.89	0.73	0.54	3.81	0.78	0.31	0.22	0.60	38.77
1/1/72	247	13.09	13.71	4.85	1.53	4.57	1.26	3.17	0.84	0.63	4.26	0.82	0.29	0.22	0.62	41.47
Incremental Change																
1962-1972		3.08	3.12	1.18	(0.28)	0.82	(0.21)	1.15	0.43	0.08	1.89	0.36	–	0.01	0.13	22.57
% Crude		100.0	101.3	37.8	(9.0)	26.3	(6.7)	36.9	13.8	2.6	60.6	11.5	–	0.3	4.2	–
NPC Questionnaire & Expansion Data (MMB/CD)																
1973-1978		1.8	–	0.50	(0.18)	0.20	0.0	0.67	0.11	0.67	0.99	0.13	0.14	0.18	0.09	6.4
% Crude		100.0	–	28.0	(1.0)	11.0	0.0	37.0	6.0	37.0	55.0	7.0	8.0	1.0	5.0	–

*Aromatic and isomerization reported beginning 1/1/69.

Source: *Oil and Gas Journal*, Annual Refining Reports (January 1, 1962 through January 1, 1972); NPC Refining Survey Questionnaire (1973 through 1978).

TABLE 3

TRENDS IN DOWNSTREAM PROCESSING UNIT CAPACITY
(Percent of Crude)

Date	Crude Ratio*	Charge Capacity: Vacuum Distillation	Thermal Operation	Catalytic Cracking (Fresh Feed)	Catalytic Reforming	Catalytic Hydro-Cracking	Catalytic Hydro-Refining	Catalytic Hydro-Treating
1/1/62	100.0	34.7	17.1	35.4	19.1	0	0	22.4
1/1/63	98.8	34.3	16.7	37.2	19.0	0	0	24.3
1/1/64	101.2	35.0	16.0	37.2	19.1	0	0	25.6
1/1/65	101.6	35.0	15.2	37.1	19.2	0	0	27.2
1/1/66	101.5	35.0	15.7	36.9	19.4	0	0	28.8
1/1/67	103.4	35.5	15.0	36.1	20.0	0	0	30.6
1/1/68	110.1	35.0	14.2	35.9	20.5	3.48	0	31.4
1/1/69	114.1	34.1	13.3	35.2	21.0	4.11	4.54	27.1
1/1/70	119.5	35.9	12.9	34.6	21.9	4.77	4.30	27.7
1/1/71	125.4	35.7	11.7	34.0	21.7	5.51	4.04	28.7
1/1/72	129.5	35.4	11.2	33.3	23.1	6.12	4.62	31.1

Date	Crude Ratio†	Production Capacity: Alkylation	Lubes	Asphalt	T/MB‡ Coke
1/1/62	100.0	4.38	1.98	4.59	1.78
1/1/63	98.8	4.68	1.91	4.67	1.84
1/1/64	101.2	4.70	1.87	4.74	1.95
1/1/65	101.6	4.93	1.92	4.99	2.11
1/1/66	101.5	5.12	1.91	4.94	2.14
1/1/67	103.4	5.44	1.91	4.96	2.28
1/1/68	110.1	5.55	1.80	4.59	2.44
1/1/69	114.1	5.55	1.66	4.75	2.44
1/1/70	119.5	5.92	1.65	4.61	2.81
1/1/71	125.4	5.84	1.67	4.51	2.92
1/1/72	129.5	6.00	1.59	4.52	3.03

*Calculated on annual stream day capacity data (see Table 2).
†Calculated crude capacity as percent of 1/1/62 stream day capacity (see Table 2).
‡Tons of coke per thousand barrels of crude charge.

roots refinery to go on-stream. This trend may continue for the next few years because of uncertainties concerning crude oil supplies, lead usage, refinery sites, environmental protection problems and the availability of capital.

Vacuum Distillation

The charge rate to vacuum distillation units has increased at about the same rate as total crude oil distillation capacity and reached 4.85 MMB/SD in 1972.

Thermal Operations

One of the most significant changes in refinery processes has been the decline of thermal operations. Since the end of 1961, their combined capacity has decreased from 1.8 MMB/CD to slightly over 1.5 MMB/CD--as a precent of crude charge their capacity has dropped from 17.1 percent to 11.2 percent. Classified in thermal operations are gas/oil crackers, visbreakers, fluid coking, delayed coking and others. As coke production has increased from 18.90 to 41.47 M tons per day, the capacity of fluid and delayed coking units has increased during this period; therefore, the other thermal operations must have experienced sharp reductions to offset this increase. Most of this capacity has been diverted to catalytic crackers and to the new hydrocrackers which provide a more desirable product distribution. The NPC survey indicates that refineries are not including thermal operations in their future expansion.

Catalytic Cracking

In terms of throughput, the catalytic crackers are among the largest units in a refinery. From 1962 to 1965, they showed a slight increase in fresh feed capacity from 35.4 percent of total crude inputs to 37.1 percent. Since 1965, with more active zeolite catalyst gaining in popularity, and with the development of hydrocracking processes, catalytic cracking capacities have increased from 3.99 MMB/SD to 4.57 MMB/SD, but have declined as a percent of crude charge from 37.1 percent to 33.3 percent. The zeolite catalyst with its improved selectivity has permitted the refineries to increase conversion rates without having to expand regenerator and gas processing facilities. The new catalysts and other developments, such as the introduction of hydrocracking and the reduction in thermal cracking, have allowed the refineries to increase their total gasoline yields.

Recent environmental regulations are creating significant additional capital expenditure requirements. Many feedstocks must be hydrotreated and stack gas desulfurization units and additional catalyst recovery systems are being required. These factors result in the overall capital requests for cat cracking being competitive with those of hydrocracking.

Catalytic Reforming

There was little change in reforming capacity during the years 1962 through 1966, when capacity remained at slightly over 2.0 MMB/SD, or 19.1 percent, of crude capacity. Since then, it has increased to almost 3.2 MMB/SD with an average growth rate of 7.7 percent per year. In 1971, the increase was 9.7 percent and the trend is expected to continue. The strong demand for catalytic reforming is due to the anticipated requirement to reduce lead levels in motor fuel according to Environmental Protection Agency regulations and to use aromatics for chemical feedstocks.

Another factor has been the increase in hydrocracking capacity, which produces naphthas that sometimes need to be upgraded via catalytic reforming. The NPC survey data confirm that reforming capacity is expected to continue to grow; for the 1973-1978 period it is estimated at 37 percent of the proposed crude expansion. Recent developments have resulted in more selective, higher yield and longer life reforming catalysts. Higher reforming severity operation processing lower quality feedstocks is now economical.

Hydrocracking

Hydrocracking, a relatively new commercial process, enables refineries to produce varying ratios of gasoline from middle distillates, thus improving flexibility. It is considerably more expensive than catalytic cracking, and so, in many cases, it has been used only to supplement catalytic cracking capacity. Since 1968, the hydrocracking capacity has more than doubled, increasing from .4 MMB/SD to .8 MMB/SD. This process has had a phenomenal growth rate which has averaged approximately 27 percent per year; however, with the current slack in refinery expansion, its growth rate has also declined, and in 1971 it was only 14.7 percent.

The combined capacity of hydrocracking and catalytic cracking has remained at approximately 39.5 percent of the crude charge, indicating a fairly constant amount of feed available to either process. Of this total, hydrocracking now accounts for 6.1 percent compared to 3.5 percent in 1968, indicating a definite preference for hydrocrackers in the last few years. Although this process may be slightly more expensive than catalytic cracking, the problems involved in securing feedstocks for the hydrogen required by hydrocracking are becoming more severe as natural gas supplies dwindle.

Catalytic Hydrorefining

Since 1968, the capacity for catalytic hydrorefining has not changed as a percent of the crude charge. Future plans show a significant increase in catalytic hydrorefining, with most of the growth attributable to the need for further reductions in distillate sulfur levels. The questionnaire results did not indicate any plans for direct desulfurization of residuum.

Catalytic Hydrotreating

Hydrotreating has grown from 2.4 MMB/SD capacity in 1962 to 4.3 MMB/SD in 1972. With the introduction of bimetallic catalysts for reforming, many refiners have built new naphtha hydrodesulfurization units to desulfurize naphthas to the very low sulfur levels required for these catalysts. With the emphasis on lowering distillate sulfur levels, refineries have also increased distillate hydrotreating capacity. The combined treating capacity has increased from 22.4 percent of the crude to 31.1 percent during the last 10 years and is expected to increase by another .55 MMB/CD in the next 5 years.

Alkylation

Total alkylate capacity during this period has almost doubled, increasing from 0.46 MMB/SD to 0.82 MMB/SD. As a percent of the crude charge, it has also shown a substantial increase; it went from 4.38 percent in 1962 to 6.00 percent in 1972. Most of this increase can be attributed to the new zeolite catalyst for catalytic crackers which has increased conversion and selectivity levels for producing additional olefin feedstock for alkylation units. Also, many refineries are including more propylenes in their feedstocks, a result of improved recoveries or diversion from other usage. Since alkylate has a high clear (unleaded) octane number, it is one of the more desirable blending stocks for motor fuel, especially if additional reductions in lead usage are needed.

Lube Oils

Lube oil production has increased very little over the past few years, possibly indicating that improvements in service life have offset the increased demand. Production of lube oil as percent of crude input declined from 1.98 percent in 1962 to 1.59 percent in 1972.

Asphalt

As a percent of crude charge, asphalt demand has kept pace with refinery growth and has increased from 0.49 MMB/SD to 0.62 MMB/SD over the 10 year period 1962-1972.

Coke

Petroleum coke production has more than doubled in the last 10 years, increasing from 18.90 to 41.47 M tons per day. This change has produced more gas oil for catalytic crackers and/or hydrocrackers as more residuals have been diverted from fuel oil to coking processes. Besides allowing the refinery to produce at a higher gasoline to distillate ratio, coking lowers the sulfur content of the fuel oil produced.

PROJECTED DOMESTIC CAPACITY THROUGH 1985

Based on the results of the NPC questionnaire, the operating capacity of U.S. refineries as of January 1, 1973, was 13.2 MMB/CD. This total represents nearly 12.3 MMB/CD of reported operating capacity and slightly under 1.0 MMB/CD of capacity operated by companies not responding to the questionnaire. This capacity compares

TABLE 4

U.S. OPERATING REFINING CAPACITY
QUESTIONNAIRE RESPONSE
(MMB/CD)

	1973	1974	1975	1976	1977	1978
Beginning-Year Capacity	13.2	13.2	13.5	13.9	14.6	14.6
Add: Grassroots	—	0.1	0.1	0.4	—	0.3
Expansion	*	0.2	0.4	0.4	0.1	0.1
Less: Abandonment	*	—	0.1	0.1	0.1	—
Year-End Capacity†	13.2	13.5	13.9	14.6	14.6	15.0
Mid-Year Average Capacity	**13.2**	**13.3**	**13.7**	**14.3**	**14.6**	**14.8**

* Less than 0.1.

† Includes 1.0 MMB/CD capacity not reported to questionnaire.

with the 13 MMB/CD of total U.S. operating capacity as reported to the Bureau of Mines as of January 1, 1972.

Results of questionnaire responses were also tabulated for planned refinery expansions, abandonments and grassroots construction through 1978. These are shown on Table 4. These changes to capacity and the resulting total capacity based on survey results reflect plans as of late 1972. Changes in the political and economic climate are not reflected.

An analysis of historical capacity, shown on Table 5, indicates that the growth rate was 1.2 percent per year for 1960-1965, and

TABLE 5

TOTAL U.S. OPERATING REFINING CAPACITY
ACTUAL AND PROJECTED*

	Number of Refineries	Total U.S. Mid-Year Refining Capacity (MMB/CD)	Average Annual Growth Over 5-Year Period %	Average Annual Growth Over 5-Year Period MMB/CD
1960	290	9.6	—	—
1965†	273	10.2	1.2	0.1
1970†	262	12.3	3.8	0.4
1975	—	13.7	2.2	0.3
1980	—	15.6	2.6	0.4
1985	—	17.4	2.2	0.4
1970-1985 Average			**2.3**	0.3

* Not a forecast.
† Average beginning and ending of year (see Table 50).

3.8 percent per year for 1965-1970. A statistical projection which utilizes the historical and questionnaire data shows a growth rate of 2.3 percent per year from 1970 to 1985 (see Figure 5).

Shown in Figure 6 are historical and projected crude oil throughput rates to refineries. In this figure and in all projections of required refining capacity, a 92 percent refinery utilization factor has been used (i.e., 92 barrels of actual crude throughput for each 100 barrels of crude oil distillation capacity). Historical experience shows that this represents the highest rate which has been sustained by the industry on a year-in-year-out basis. The question of the industry being unable to run at 100 percent of rated crude distillation capacity arises from the anomaly in the definition of a "crude distillation capacity." It does not take into account the fact that other materials, such as natural gas liquids, unfinished oils and partially refined oils are often run in the crude distillation unit. A refinery is a continuous flow operation, and any imbalances in the capacity of essential downstream units, such as catalytic cracking and catalytic reforming units, can restrict the overall refinery input volume. Operating capacity cannot be recovered if problems occur when operating at maximum rates. Variations in crude oil supply, type and trans-

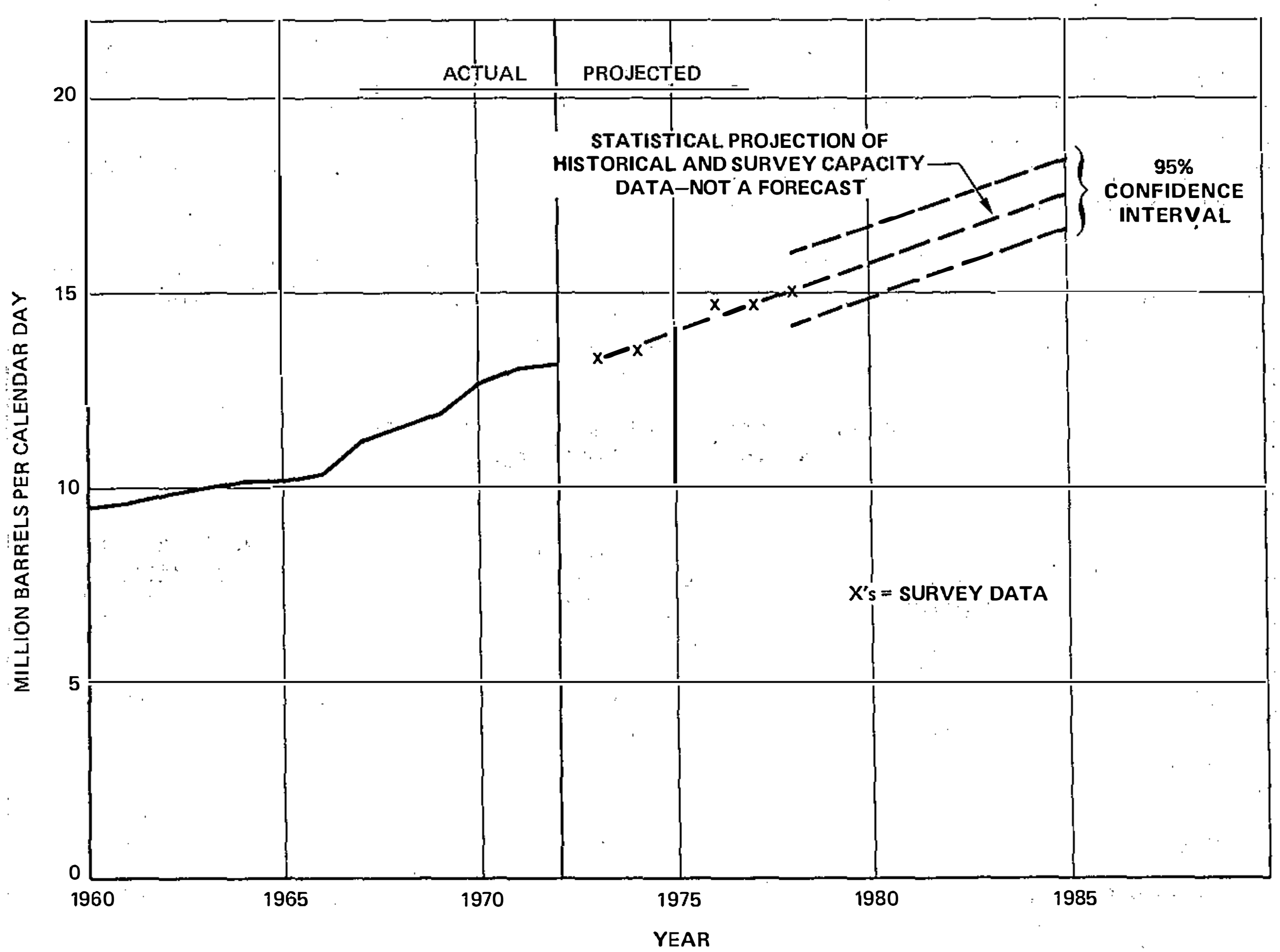


Figure 5. Range of Projected U.S. Operating Refining Capacity--1978-1985.

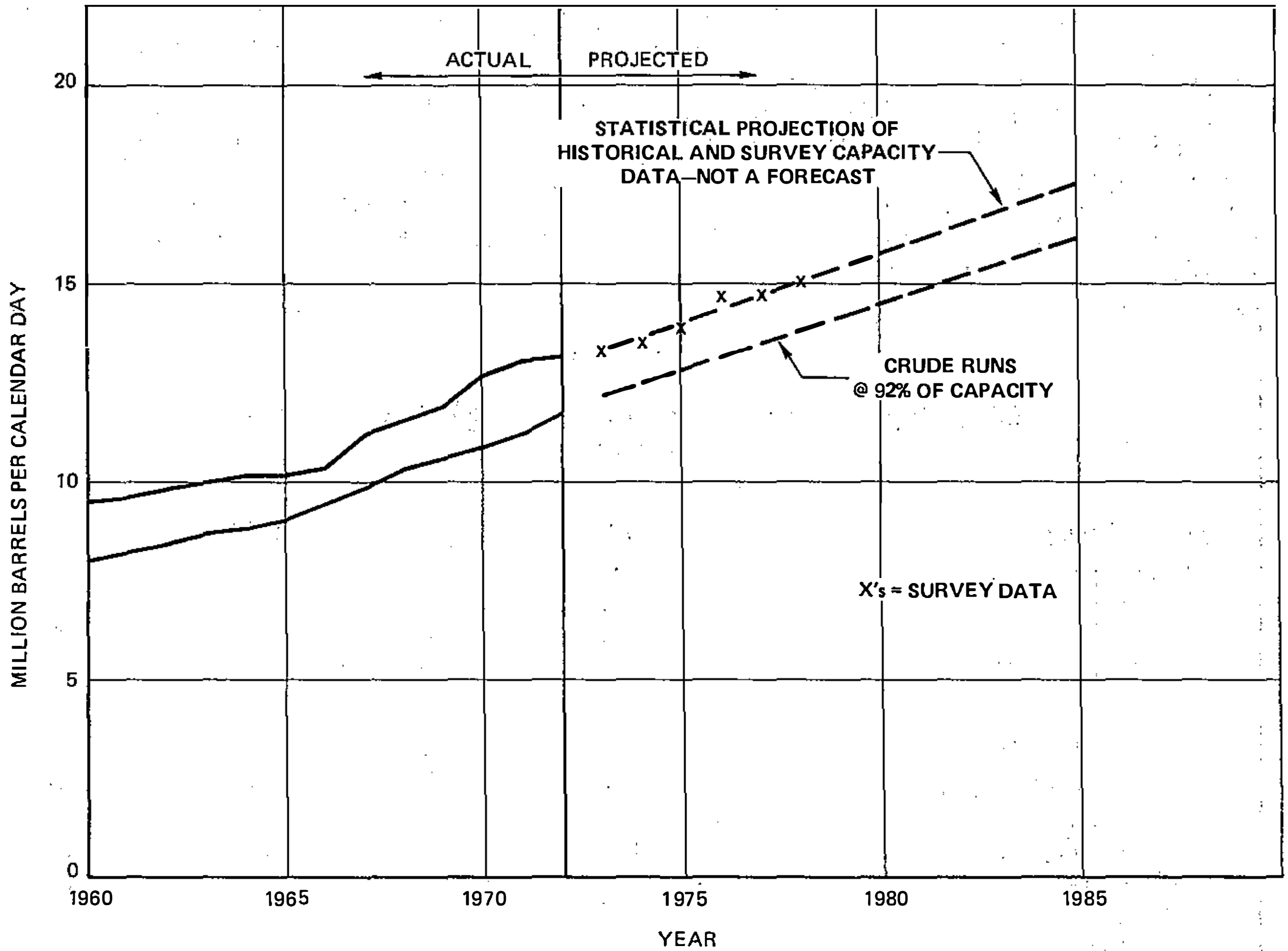


Figure 6. Total U.S. Operating Refining Capacity and Crude Runs (Year-End Capacity)--1960-1985.

portation, as well as such factors as unexpected process unit downtime, make the use of an overall industry utilization factor necessary.

REFINING CAPACITY SHORTFALL

Until recently, the shortfall in production by U.S. refineries has been primarily confined to residual fuel oil. This deficit developed over many years and was essentially attributable to the underlying economics of fuel use patterns and domestic refining. As the real price of industrial fuels fell, domestic refiners became increasingly unable to compete. Foreign refiners with unlimited access to low-cost foreign crude could build relatively simple and inexpensive refineries to supply the U.S. heavy fuel oil market at a cost competitive with gas and coal. Import policies recognized the prevailing economics affecting the manufacture of residual fuel oil in the United States and provided accordingly for liberal importation of heavy oils.

Under these circumstances, refinery capacity to meet demand for heavy oils in the United States was increasingly built in the offshore areas adjacent to the U.S. markets, and U.S. capacity was designed to increase light product yields. The economics for an offshore refinery to produce fuel oil are, however, changing. Low-cost and low-sulfur foreign crude oil supplies which provided incentives for offshore manufacture of heavy fuel oil are in tight supply. Additionally, demand for low-sulfur fuel oil has increased substantially and, in order to increase production levels, refiners may have to install costly desulfurization equipment when appropriate crudes can be obtained.

TABLE 6

COMPOSITION OF U.S. IMPORTS OF REFINED PETROLEUM PRODUCTS*
(MB/CD)

Product Group	1960	1965	1970	1972
Light Products				
Gasoline	27	27	67	68
Jet Fuels	34	81	144	195
Middle Distillates (Ex. No. 4 Fuel Oil)	35	36	81	97
LPG	4	21	52	89
Petrochemical Feedstocks	—	1	15	8
Solvent Naphthas	—	8	6	2
Total Light Products	100	174	365	459
Heavy Products				
Residual Fuel Oil	637	946	1,528	1,742
No. 4 Fuel Oil†	—	—	70	85
Asphalt	17	17	17	25
Lubricants and Wax	—	—	1	3
Total Heavy Products	654	963	1,616	1,855
Natural Gasoline and Plant Condensate	—	—	6	86
Unfinished Oils	45	92	108	125
Total NGL‡ and Unfinished Oils	45	92	114	211
Total Product Imports	799	1,229	2,095	2,525
Bonded Products Included Above				
Light Products	20	51	144	179
Heavy Products	104	136	117	125
Total Bonded	124	187	261	304
Imports for Consumption				
Light Finished Products	80	123	221	280
Heavy Finished Products	550	827	1,499	1,730
Total Finished Products Imported for Consumption	630	950	1,720	2,010
NGL and Unfinished Oils	45	92	114	211
Total Imports for Consumption	675	1,042	1,834	2,221

* Data from U.S. Department of Commerce, as reported by Bureau of Mines.

† Census classified No. 4 fuel oil as distillate fuel and industry as a heavy fuel.

‡ Natural gas liquids.

Generally, however, U.S. domestic refining capacity was adequate to meet refined product demand until the 1960's. Since that time, a shortfall in refining capacity has been developing, and total product imports have been increasing sharply (see Table 6). It should be noted that a large share of the total imports were heavy fuel oils and that a large share of the light product imports were bonded fuels. Also, a large portion represented unfinished oils imported for final processing in U.S. refineries. Table 7 shows the trend in refinery capacity utilization over the last 12 years. As a rule, the physical capacity has existed to meet total light product demands. In 1972, U.S. product demand increased more than 1.1 MMB/CD, or 7.4 percent. Domestic capacity plus authorized imports became insufficient to meet demand and, as a result, large drawdowns of inventories occurred. Current industry projections for 1973 show that another large increase in demand may be expected, and, therefore even higher levels of product imports will be required to meet demands.

Figure 7 provides a graphic demonstration of the widening spread between refinery capacity required to satisfy total demand for products and the estimated refining capacity to be available. For 1975, the shortfall of refining capacity is projected to be 4.8 MMB/CD, or 25.9 percent. By 1980, this may increase to 26.7 percent, and in 1985 product demand is projected to exceed U.S. capac-

TABLE 7

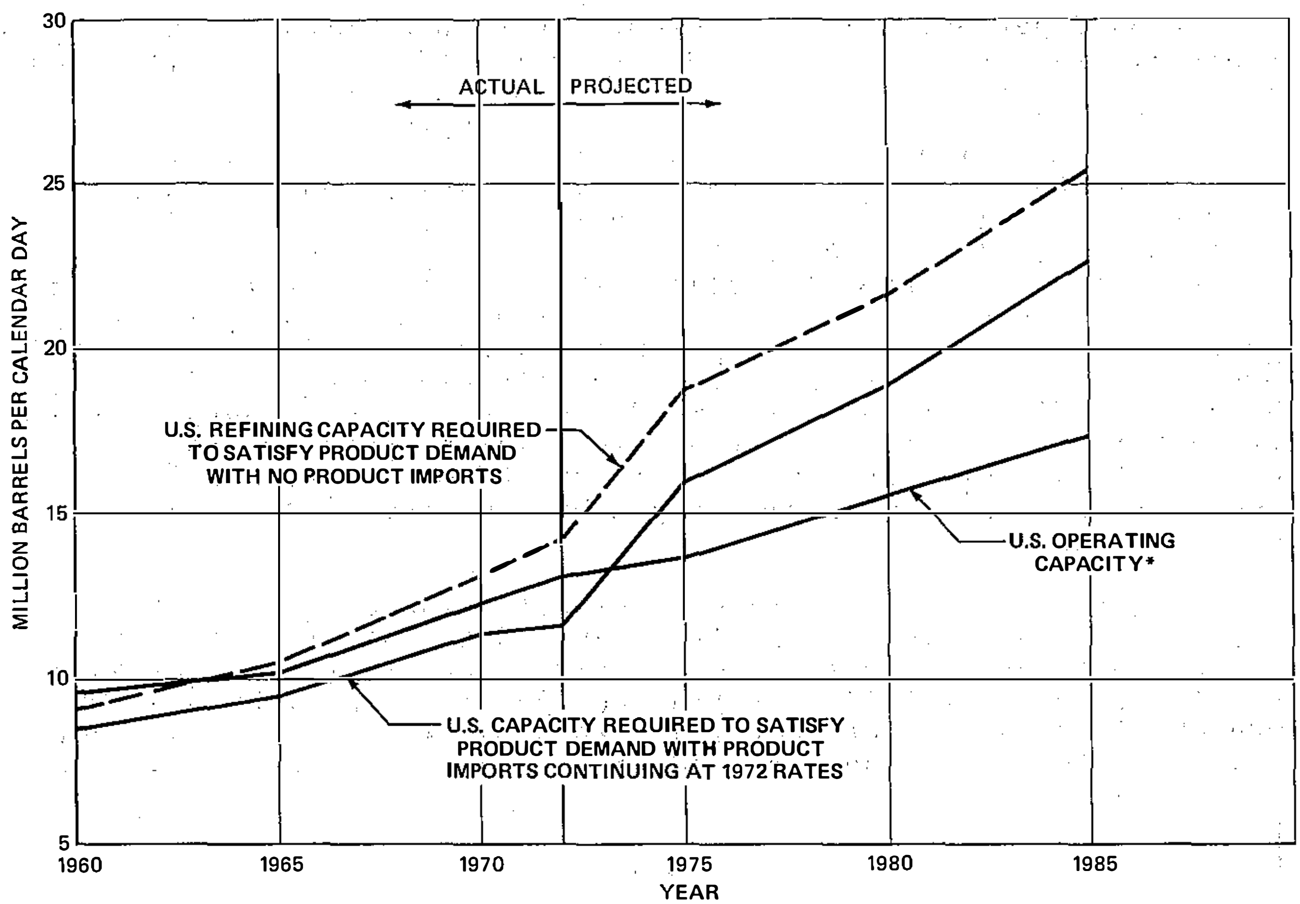
TRENDS IN U.S. OPERATING REFINING CAPACITY UTILIZATION*
(MB/CD)

	1960	1965	1970	1972
Crude Runs to Stills	8,067	9,043	10,869	11,699
Estimated NGL and Unfinished Oils Processed in Crude Units	403	452	546	586
Estimated Total Throughput in Crude Units	8,470	9,495	11,415	12,285
Average Crude Distillation Capacity (Mid-Year)	9,587	10,166	12,270	13,134(Est.)
Apparent Spare Crude Distillation Capacity	1,117	671	855	849
Finished Products Imported for Consumption†				
Light Oils	80	123	221	280
Heavy Oils	550	827	1,499	1,730
Total Finished Products Imported for Consumption	630	950	1,720	2,010
Refinery Capacity Equivalent‡	685	1,033	1,870	2,185
Apparent Shortfall in U.S. Refining Capacity to Meet Total Requirements	(432)	362	1,015	1,336

* U.S. Bureau of Mines data.

† Excluding imports in bond and fuels imported for military offshore use.

‡ Imports converted to capacity equivalent using 92-percent utilization factor.



*Statistical projection of historical and survey capacity data--not a forecast.

Figure 7. Total U.S. Operating Refining Capacity *Versus* Requirements--1960-1985.

TABLE 8

PROJECTION OF TOTAL U.S. OPERATING REFINING CAPACITY SHORTFALL 1960-1985

	Mid-Year Average Refining Capacity (MMB/CD)	Total Refining Capacity Required to Satisfy Product Demand (MMB/CD)	Shortfall MMB/CD	Shortfall %
1960	9.6	9.1	(0.5)	(5.2)
1965	10.2	10.5	0.3	2.9
1970	12.3	13.2	0.9	6.8
1972	13.1	14.3	1.2	8.4
1975	13.7	18.5	4.8	25.9
1980	15.6	21.3	5.7	26.7
1985	17.4	25.1	7.7	30.7

ity by 30.7 percent, or 7.7 MMB/CD. These data are tabulated in Table 8. Tables 9 and 10 show basic data and derivations of capacity requirements.

TABLE 9

U.S. PETROLEUM SUPPLY AND DEMAND—1970-1985
(MB/CD)

	1970 Actual	1972 Actual	1973 Estimated	Projection 1975	Projection 1980	Projection 1985
Total U.S. Product Demand	14,942	16,589	17,600	19,800	22,550	26,200
Operating Refining Capacity						
(Mid-Year Average)	12,270	13,134	13,234	13,735	15,614	17,359
Refinery Crude Runs*	10,869	11,699	12,175	12,636	14,365	15,970
Unfinished Oil Reruns (Net)	105	141	150	200	250	300
Process Gain	359	388	400	415	500	550
Product Output	11,333	12,228	12,725	13,251	15,115	16,820
Supply Factors						
NGL Transfers	1,663	1,827	1,860	1,700	1,600	1,500
Other Hydrocarbon Inputs	17	28	30	48	75	150
Crude Transfers to Fuel Oils	14	12	12	12	12	12
Finished Product Imports						
Bonded Fuels	261	304	325	375	500	625
Imports for Consumption†	1,720	2,010	2,648	4,414	5,248	7,093
Decrease in Product Inventories	−66	180	—	—	—	—
U.S. Refining Output	11,333	12,228	12,725	13,251	15,115	16,820
Total Supply	14,942	16,589	17,600	19,800	22,550	26,200

* Refinery crude runs calculated at 92 percent of refinery capacity—1973-1985.

† Imports for consumption assumed to balance supply/demand—1973-1985.

TABLE 10

APPARENT SHORTFALL IN U.S. OPERATING REFINING CAPACITY 1973-1985
(MB/CD)

	1973 Base	1975	1980	1985	1985 over 1973*
Average Operating Refining Capacity	13,234	13,735	15,614	17,359	4,125
Finished Products for Imports Required to Balance Supply/Demand	2,648	4,414	5,248	7,093	4,445
Capacity Equivalent of Product Imports†	2,878	4,798	5,704	7,710	4,832
Capacity Required to Meet Total Product Requirements	16,112	18,533	21,318	25,069	8,957

* To meet demands and replace all product imports by 1985, capacity required:
1985 – 25,069
1973 – 13,234
11,835 MB/CD or approximately 1 MMB/CD per year growth in capacity required.

† At 92-percent utilization factor.

Oil imports must rise rapidly in the short term, in order to cover the growing gap between total requirements and domestic production. Oil import policies, crude supply, comparative economics of U.S. and offshore refineries, and environmental concerns bear importantly on how much oil refining capacity will be built in the United States during the next 15 years. This, in turn, will determine the ratio between crude and product imports. Unless sufficient refinery capacity is added to meet growing consumer needs for non-residual products, the United States will be forced into reliance on imported light products (e.g., motor gasoline, aircraft fuels and home heating oils) and will continue to be dependent on imports of heavy fuel oil.

Table 11 presents historical year-by-year information for the 6 years 1967-1972 on refining capacity, product imports and total demands. These data are presented for the total country as well as for PAD Districts. Overall refining capacity decreased as a percent of product demand from 83.8 to 80.1 percent. Refined product imports as a percent of total demand has steadily increased from 11.0 percent to 15.3 percent to a level where total U.S. product imports reached 2.5 MMB/CD in 1972. Refining capacity increased 2.32 MMB/CD in this 6 year period. At the same time, imports increased 1.09 MMB/CD. Thus, refining capacity has been unable to keep up with the increasing demand through this period.

PAD District I has the largest population and is in the worst position of any district with respect to self-sufficiency. In 1972, crude capacity was only 23.5 percent of product demand. About 2.1 MMB/CD of products are imported from offshore (83 percent of the U.S. total), and about 3 MMB/CD are pipelined in from the South and Southwest. There has been essentially no growth in the refining capacity of this district in the past 6 years.

PAD District II has shown a decrease in refining capacity in relation to product demand from 85.6 to 70.5 percent. Essentially no products are imported from offshore. The needed products come in from District III, which has maintained about 200 percent of refining capacity compared to the product demand. This accounts for the ability to ship via pipeline and water into Districts I and II. Districts IV and V are just about able to supply all their demands with a miminum of product imports.

FOREIGN EXPORT CAPACITY ON U.S. PERIMETER

In the preceding sections, 1985 U.S. requirements for refining capacity were projected to exceed current capacity by 12.0 MMB/CD and to exceed projected 1985 capacity by 7.7 MMB/CD. In an effort to define worldwide availability of refined products to meet both U.S. incremental demand and U.S. 1985 indicated shortfall, an analysis was made of non-Communist foreign refining capacity and trends.*

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* The detailed analysis is given in Appendix E and is summarized here. For further information see Office of Oil and Gas, Department of the Interior, *Trends in Capacity and Utilization*, December 1972.

TABLE 11

OPERATING REFINING CAPACITY AND PRODUCTS IMPORTED
RELATED TO TOTAL DOMESTIC DEMAND
(MMB/CD)

	1967	1968	1969	1970	1971	1972
			Total U.S.			
Operating Refining Capacity (Average)	10.79	11.37	11.73	12.27	12.85	13.13
Products Imported	1.41	1.55	1.76	2.10	2.24	2.5
Total Domestic Demand	**12.88**	**13.63**	**14.38**	**14.99**	**15.44**	**16.37**
Operating Refining Capacity (Percent)						
Total Demand	**83.8**	**83.4**	**81.6**	**81.9**	**83.2**	**80.1**
Products Imported (Percent)						
Total Demand	**11.0**	**11.4**	**12.3**	**14.0**	**14.5**	**15.3**
			PAD District I			
Operating Refining Capacity	1.41	1.45	1.44	1.48	1.52	1.53
Products Imported	1.25	1.40	1.57	1.87	1.96	2.08
Total Demand	**5.05**	**5.33**	**5.52**	**5.91**	**6.06**	**6.5**
Operating Refining Capacity (Percent)						
Total Demand	**27.9**	**27.2**	**26.0**	**25.0**	**25.1**	**23.5**
Products Imported Offshore (Percent)						
Total Demand	**24.8**	**26.3**	**28.5**	**31.6**	**32.3**	**32.0**
			PAD District II			
Operating Refining Capacity	3.05	3.16	3.22	3.36	3.48	3.56
Products Imported	.02	.02	.02	.05	.06	.10
Total Demand	**3.56**	**3.72**	**3.92**	**4.02**	**4.14**	**4.48**
Operating Refining Capacity (Percent)						
Total Demand	**85.6**	**89.9**	**82.1**	**83.6**	**84.1**	**79.5**
Products Imported Offshore (Percent)						
Total Demand	**0.6**	**0.5**	**0.5**	**1.2**	**1.4**	**2.2**
			PAD District III			
Operating Refining Capacity	4.24	4.58	4.74	5.03	5.35	5.49
Products Imported	.03	.03	.04	.06	.05	.06
Total Demand	**2.08**	**2.23**	**2.54**	**2.59**	**2.69**	**2.61**
Operating Refining Capacity (Percent)						
Total Demand	**204**	**205**	**187**	**194**	**199**	**210**
Products Imported (Percent)						
Total Demand	**1.4**	**1.3**	**1.6**	**2.3**	**1.9**	**2.3**

TABLE 11 (CONT'D.)

OPERATING REFINING CAPACITY AND PRODUCTS IMPORTED RELATED TO TOTAL DOMESTIC DEMAND (MMB/CD)

	1967	1968	1969	1970	1971	1972
			PAD District IV			
Operating Refining Capacity	.39	.42	.42	.42	.42	.42
Products Imported	—	.01	.01	.01	.02	.04
Total Demand	.35	.39	.37	.38	.42	.43
Operating Refining Capacity (Percent)						
Total Demand	111	107	114	102	100	97
Products Imported (Percent)						
Total Demand	—	2.6	2.7	2.7	4.7	9.3
			PAD District V			
Operating Refining Capacity	1.70	1.77	1.87	1.97	2.08	2.16
Products Imported	.11	.09	.11	.11	.14	.13
Total Demand	1.83	1.96	2.03	2.07	2.12	2.14
Operating Refining Capacity (Percent)						
Total Demand	92.9	90.3	92.1	95.2	98.1	101
Products Imported (Percent)						
Total Demand	6.0	4.6	5.4	5.3	6.6	6.1

Basis of Numbers:

- Imports were taken from Bureau of Mines figures.
- Total demands and PAD demand are Bureau of Mines numbers.
- Operating refining capacity imports and demand numbers are expressed as barrels per calendar day.
- 1972 numbers were compared with the first six months of 1971 and then ratioed for the total year of 1972.
- The demand numbers have no correction applied as far as relating refinery yields to crude input.
- Operating refining capacity plus product imports should not equal product demand due to added inputs such as NGL and the fact that crude distillation capacity does not always equal crude runs.
- Operating refining capacity is an average of start of year and end of year.
- NGL is not included in balances.

Of particular interest is the capacity of the so-called perimeter exporting refineries--those located in Canada, the Caribbean and Latin America. While other export refining capacity, such as Italian or Persian Gulf, may be available to supply products to the U.S. market, they are generally at an economic disadvantage to perimeter export refineries because of transportation.

It was found that foreign refineries on the U. S. perimeter can cover a portion of the anticipated refining capacity shortfall. However, the growth rate required for this additional capacity will have to exceed prior rates. Hence, if no action is taken to expand domestic capacity, offshore capacity may not be sufficient to meet the demand.

TABLE 12
FOREIGN EXPORT REFINING CAPACITY ON U.S. PERIMETER*
(MB/CD)

	1950	1955	1960	1965	1970	1971	1972	1975	
Location									
Canada	–	–	–	–	–	–	184	284	
Caribbean	755	1,204	1,705	2,095	2,755	3,062	3,272	3,965	
Other Latin America	–	–	–	–	–	–	–	–	
Total	755	1,204	1,705	2,095	2,755	3,062	3,456	4,249	
					Avg. 1965	Avg. 1970	Avg. 1971	Over 1972	Over 1970
Average Year-to-Year Increase	–	90	100	78	132	287	394	264	299
Compound Percent Increase per Year Over Previous Period	–	9.8	7.3	4.2	5.7	11.1	12.8	7.2	9.1
Memo: Crude Runs Based on 92% Utilization Factor	695	1,144	1,569	1,927	2,535	2,817	3,180	3,909	
Memo: Mid-year Average Crude Runs	–	–	–	–	2,700	–	–	3,900	

* Start-of-year basis. See Appendix E, Intermediate and Resource Refineries sections. B/SD converted to B/CD by applying 0.95 factor.

The historical growth of perimeter refineries is shown in Table 12. The refineries included are defined as resource refineries and intermediate refineries. Resource refineries are those near a producing area (in this case, specifically Venezuela) producing products for export. Intermediate refineries are built between crude source and market, generally along major trade routes. Both Caribbean refineries and Canadian Maritime Province refineries meet these definitions.

Table 13 compares growth rates and annual expansion of perimeter refineries under several assumptions. To continue to make up about all of the domestic shortfall, under the assumption that no additions are made to U.S. capacity, would require growth rates and capacities beyond any exhibited to date by these refiners--i.e., a 1970-1975 peak of 12.2 percent *versus* a 1950-1955 historical peak of 9.8 percent, at a much lower base.

It can be concluded that if U.S. domestic refining capacity does not increase above projected levels, domestic plus perimeter capacity may be unable to meet U.S. product demands, and some additional refined material would have to move in from other areas. But logistics--the economics of moving a multiplicity of products *versus* those of moving crude oil and unfinished oils--are heavily against any such significant operation.

TABLE 13

ALTERNATIVE GROWTH OF PERIMETER REFINERIES
(MMB/CD)

	1975	1980	1985
U.S. Shortfall from Table 8*			
No U.S. Expansion *vs.* 1972 Mid-Year Average	5.4	8.2	12.0
With Projected U.S. Expansion	4.8	5.7	7.7
Perimeter Refineries Reported Existing and Planned Capacity*	4.0	—	—
Percent/Year Growth†	9.1		
Average Annual Addition	.3		
Total Capacity of Perimeter Refineries Required to Meet Total U.S. Shortfall*	4.8	5.7	7.7
Percent/Year Growth†	12.2	3.5	6.2
Average Annual Addition	0.4	0.2	0.4

* Shortfall and expansion capacity based on actual needs; refinery additions based on 0.92 utilization factor.

† Percent per year over preceding 5-year period.

Chapter Two

FACTORS AFFECTING REFINING SHORTFALL AND ENVIRONMENTAL CONSIDERATIONS

FACTORS AFFECTING DEMAND FOR CAPACITY

There are four major factors affecting the need for crude oil and petroleum products:

- The demand for energy in the United States which is projected to grow at an average rate of 4.2 percent per year through 1985.
- The supply of natural gas which has become very short due to increasing demands exceeding discoveries.
- Environmental concerns which have greatly contributed to the delay in many nuclear power plants being constructed or going on-stream.
- Environmental legislation which is causing, or will cause, the displacement of high-sulfur coal and fuel oil and leaded motor gasoline by low-sulfur fuel oil and low-lead or unleaded motor gasoline.*

Fluctuations in total oil demand and in demand for individual products stem from the fact that, although oil is not completely interchangeable with other fuels in existing equipment, it can supply the needs in any energy sector of our economy. In effect, it can act as a "swing" fuel. If natural gas finding rates are disappointingly low in the future, oil can be used to fill the need. The same concept holds true for oil as an alternate to nuclear power and coal when appropriate.

The power industry's efforts to utilize nuclear power plants have been delayed by construction lead time problems, cooling water discharge standards and environmental court actions. There are not sufficient production facilities for low-sulfur coal, and there are not sufficient reserves of low-sulfur coal within reasonable distances to satisfy the demand--93 percent being a long distance from the major demand. Thus, many power plants have been, or will be, converted to run on low-sulfur fuel oil. This conversion has increased the demand for fuel oil over normal rates, thus contributing to the current low-sulfur fuel oil shortages.

** In his April 18, 1973, energy message, the President affirmed EPA's call to use the most environmentally desirable fuels only for attainment of "Primary" air quality standards (those related to health) as outlined by the 1970 Clean Air Act Amendments and allow orderly attainment of the more stringent "Secondary" standards (those related to general welfare).*

Additionally, the supplies of low-sulfur crude oil are limited, and their worldwide availability will tighten as countries compete more vigorously in the world market for a limited resource. Also, low exploration finding rates and limited lease sales have led to few new domestic sources of oil being developed.

On January 10 and October 12, 1973, the EPA published in the *Federal Register* its regulations requiring the general availability of unleaded gasoline by July 1, 1974. These regulations were issued on the premise that a catalytic device was necessary to control auto emissions, that a suitable device (50,000 mile life) could be developed and that lead would poison the catalyst. EPA also proposed that leaded grades of gasoline be limited to 2.0 grams per gallon of lead by January 1, 1975, and 1.25 grams per gallon by January 1, 1978.*

One direct effect of the techniques used to control these emissions is that a vehicle's fuel efficiency is lowered. As a result, it is necessary to process more crude oil in order to produce the additional gasoline that is required. Restricting the use of lead additives in gasoline will require refiners to use still more crude oil in order to produce more high-octane gasoline components. The cumulative effect of these requirements could cause an increase in our need for crude oil distillation capacity by 1985 beyond that shown in Figure 7, Chapter One.

FACTORS AFFECTING EXPANSION OF REFINING CAPACITY

Location of Additional Capacity

Within today's political, social and environmental climate there are many restrictions imposed by regulatory authorities which are contributing to the shortfall of refining capacity. Data from the NPC industry survey indicate that refinery expansion can take place at existing locations. These expansions are subject to obtaining permits under local zoning and environmental ordinances and are in accordance with all federal regulations. The thrust of the question on the survey, along with later amendments, was to determine from each refiner the expansion capability of current refinery sites based on land availability while giving consideration to factors such as crude supply, markets for products and environmental limitations. As to probability of obtaining permits, a range of 0.0 to 1.0 was used, with a rating of 1.0 being given to sites where a refiner believed he would have no problems obtaining permits. At several locations on the East Coast, the probability was as low as 0.5; on the West Coast an instance of 0.3 was estimated; and in the rest of the Nation, there was only an occasional 0.7. By applying

* On December 6, 1973, the EPA published regulations stating that the maximum 3 month average lead content of the total gasoline pool at any refinery will be limited to 1.7 grams per gallon by January 1, 1975, and phased down on a yearly basis to 0.5 grams per gallon by January 1, 1979.

the probability factors to the reported expansion the following probable expansion capabilities of present refineries were determined:

PAD District	Probable Expansion Capability of Present Refineries (MMB/CD)	Percent of January 1, 1972 Capacity
I	1.7	111.2
II	2.5	72.0
III	4.1	75.1
IV	0.5	118.5
V	2.0	93.2
Total	10.8	82.9

Chapter Three discusses the incentives for expanding capacity in areas where products are consumed. In these areas, local ordinances and state regulations such as Coastal Zone Acts prohibit construction within specified distances of the coastline and make the possibility of development of marine facilities very unlikely.

Consumers on the East Coast will have added costs for their products, if it is necessary to ship foreign crude oil to the Gulf Coast for refining and then ship products back to the East Coast. In view of the impending shortfall of refined products, attempting to fulfill the shortfall from foreign supply sources will impact more heavily on the East Coast consumer.

Special Problems of Small Refineries

Small refineries, whether owned by small or large companies, offer many advantages to both local areas and the Nation. These small refineries may offer a supply of products to an isolated or sparsely populated area, in both cases making a significant economic contribution to the area. The possible phasing out of many of the smaller plants (0 to 30 MB/CD capacity) can contribute to the projected future shortfall in refining capacity. These refineries cannot benefit from the economics of scale as is the case with larger refineries. In the 0 to 10 MB/CD of crude throughput class, there are 78 refineries in the United States processing 316 MB/CD of crude oil. There are 50, 10 to 30 MB/CD throughput class refineries processing a total of about 1 MMB/CD of crude. Some of the factors creating problems which are especially acute for smaller plants are discussed in the following section.

Crude Availability and Accessibility

Much of the crude charged by refineries in the 0 to 30 MB/CD throughput class has in the past been made available through governmental preference regulation or through the ability to assign the rights to these preferences via the sliding scale provisions of the Mandatory Oil Import Program and the Outer Continental Shelf Lands Acts. Uncertainty as to the future of these preference regulations, directionally precludes investing in new refineries of this size. More importantly, if these programs are modified in such a way as to limit the availability of crude, much of the refinery capacity in this size category could become uneconomic.

Product Specification Changes

Since only a small percentage of refineries in the 0 to 30 MB/CD category have the gasoline processing capability necessary to increase octane numbers, the latest federal regulations further restricting the quantity of lead antiknock compounds which can be added to gasoline will have a significant effect on the capital requirements and economic viability of these refineries. Where higher sulfur crude oil is currently being processed, local regulations restricting the percentage of sulfur in liquid fuels will require the small refinery to either invest capital in desulfurization equipment or change to sweet crude. Sweet crude supplies on a worldwide basis are dwindling and where desulfurization is employed, product unit costs would increase disproportionately to those of larger refineries due to poor economics of scale.

Environmental Regulations

Recently promulgated federal and local regulations for effluent water quality and ambient air quality will also force the small refinery to invest heavily in pollution control equipment relative to total refinery investment. Again, the absence of economics of scale and the capability requirements will directionally decrease the economic attractiveness of refineries in this category.

UNCERTAINTY AS TO THE BASIS FOR DESIGNING NEW REFINERIES

In addition to the problems of obsolescence of present small refineries already discussed, the regulatory trends and the lack of stability in regulations in the industry have generated an atmosphere of uncertainty that has put a damper on major expansions. Perhaps the most important and least certain of the factors contributing to the uncertainty as to how to design a new refinery is the prediction of what types of crude oil will be available when the facilities are placed on-stream.

An adequate, reasonably secure supply of suitable crude oil is a necessary part of the planning for a new refinery. Many companies are dependent on the availability of crude oil from others, and even those companies which are self-sufficient could have difficulty in providing their own crude oil to a new refinery because of inadequate transportation and port facilities.

Some crude oils would not be suitable for refining in certain refineries, thereby restricting the availability even more. Such factors as sulfur content and gravity are important. A change in these characteristics necessitates a change in the facilities required to process the crude oil. For instance, if a refinery could be provided with low-sulfur domestic and foreign crude oils, a wide range of products, including low-sulfur No. 6 fuel oil, could be produced with minimim refinery facilities. On the other hand, a high-sulfur feedstock requires extensive desulfurization steps necessitating expensive corrosive resistant materials of construction throughout, thus increasing the complexity and cost of the refinery.

A similar problem exists for heavy crude oils. The more residual materials that are left after atmospheric and vacuum distillation, the more downstream processing facilities may be required. Processing the products from a coker for instance, takes more hydrogen and more expensive refining facilities than products from crude distillation or catalytic cracking.

Projections in NPC's Initial Appraisal study indicate the importation of 14.8 MMB/CD of oil (including products) in 1985. This is 11.4 MMB/CD more than was imported in 1970. The projected imports are, indeed, 3.5 MMB/CD more than the total domestic oil production in 1970. It is very likely that the bulk of the incremental oil imports will be high-sulfur Middle Eastern crude (unless political conditions limit this source). As shown in Table 14, almost 70 percent of the Free World 1970 oil reserves are in the Middle East, and about 80 percent are in member countries of the Organization of Petroleum Exporting Countries (OPEC). Unfortunately, from an environmental standpoint, most of this oil is of high-sulfur content.

The close proximity of other markets to African, Asian/Pacific and European oils, many of which are low in sulfur, is such that little incremental demand in the United States can be expected to be satisfied from these areas except at a highly competitive price. Consequently, it can be expected that the bulk of the new importations will be high in sulfur, with the medium heavy metals content characteristic of Middle Eastern crudes. This pattern could, of course, be upset by new discoveries or by increased economic pressure from producing countries.

Until fairly recently, the principal constraints on most U.S. refineries were the needs of the consumer, competition, economics and foreign crude import restrictions. Crude oils in the quantity and of the quality required to meet the Nation's demands were generally available. The use of technology having high cost or a high degree of sophistication was largely dictated by the special circumstances of the various manufacturers. The typical prime fuels refinery consisted of crude distillation units, catalytic cracking units, naphtha reformers and downstream treating facilities. Light ends from cracking operations were either converted into gasoline or consumed as fuel gas. The heavy ends of the crude were made into residual fuel oil and asphalt, the light fraction into liquefied petroleum gas (LPG) and gasoline, and the rest into middle-of-the-barrel products. Of course, some refineries made lubricating oils and other specialty products, but these are only a small fraction of refinery production.

TABLE 14

WORLD RESERVES AND PRODUCTION—1970

COUNTRY	RESERVES: Oil (MB)	RESERVES: Gas (BCF)	WELLS: Producing oil 7-1-70	WELLS: Drilling 12-1-70	OIL PRODUCTION: Estimated 1970 (MB/D)	OIL PRODUCTION: % change from 1969	No. refs.	REFINING Capacity (MB/D) January 1, 1971: Crude	Cracking	Reforming
ASIA-PACIFIC										
Afghanistan	95,000*	5,000	16*	6	46.8*	---	---	---	---	---
Australia	2,000,000	12,600	386	14	170.1	210.0	10	640.0	157.3	144.1
Brunei-Malaysia	1,000,000	6,000	592	7	146.2	8.0	3	126.5	---	6.0
Burma	40,000	80	45	10	15.6	-2.5	2	26.3	5.0	---
Cambodia	---	---	---	---	---	---	1	13.5	---	2.0
Ceylon	---	---	---	1	---	---	1	30.0	12.0	3.7
India	956,000	1,800	200	43	139.0	-8.0	10	429.3	87.7	18.8
Indonesia	10,000,000	3,000	2,136	29	861.2	17.0	6	251.2	106.5	15.0
Japan	30,000	550	1,725	15	16.3	3.2	42	3,698.8	168.1	355.8
Korea, South	---	---	---	---	---	---	2	250.0	---	24.6
New Zealand	226,000*	6,500	6†	2	.06	---	1	66.0	---	21.0
Pakistan	41,500	20,000	17	9	9.8	2.0	4	115.1	---	4.0
Philippines	---	---	---	1	---	---	4	205.0	27.7	24.6
Taiwan	20,000	800	51	8	1.7	6.2	1	118.0	10.0	8.0
Thailand	148	---	26	1	0.3	200.0	3	962.0	34.4	14.1
TOTAL ASIA-PACIFIC	14,408,648	56,330	5,200	146	1,407.1	31.7	90	6,060.9	608.7	641.7

*Condensate.
†Four Kapuni wells now producing but at no regular rate yet; tiny Moturoa field has 2 oilers.

COUNTRY	RESERVES: Oil (MB)	RESERVES: Gas (BCF)	WELLS: Producing oil 7-1-70	WELLS: Drilling 12-1-70	OIL PRODUCTION: Estimated 1970 (MB/D)	OIL PRODUCTION: % change from 1969	No. refs.	REFINING Capacity (MB/D) January 1, 1971: Crude	Cracking	Reforming
EUROPE										
Austria	180,000	431	1,268	13	54.7	7.3	2	159.5	18.0	10.0
Belgium	---	---	---	---	---	---	7	704.0	59.1	82.3
Denmark	---	---	---	---	---	---	3	196.0	31.0	33.1
Finland	---	---	---	---	---	---	2	173.0	23.0	33.6
France	125,000	7,200	324	3	47.7	-5.7	24	2,533.8	203.5	392.8
Greece	---	---	---	1	---	---	3	102.0	---	15.0
Ireland	---	---	---	1	---	---	1	55.0	---	14.5
Italy (incl. Sicily)	225,000	5,000	136	12	24.5	-15.5	36	3,235.3	624.4	356.3
Netherlands	261,000	83,000	369	7	36.5	-5.9	7	1,392.5	85.0	163.9
Norway	1,000,000*	3,000	(†)	4	(†)	(†)	3	202.0	16.0	20.0
Portugal	---	---	---	---	---	---	2	84.0	26.0	11.0
Spain	8,500	---	21	4	3.6	---	8	846.0	10.2	124.0
Sweden	---	---	---	---	---	---	5	236.0	33.0	47.5
Switzerland	---	---	---	---	---	---	2	102.0	21.0	18.3
United Kingdom	1,000,000*	36,000	60	4	1.8	-1.0	21	2,392.3	206.0	350.0
West Germany	584,000	11,900	3,065	18	147.1	-4.6	35	2,541.8	336.6	321.5
Yugoslavia	325,000	1,200	---	---	40.5	-23.6	6	222.0	23.1	32.9
TOTAL EUROPE	3,708,500	147,731	5,243	67	356.4	-6.7	167	15,177.2	1,715.9	2,026.7

*Preliminary estimate includes North Sea oil discoveries.
†To begin production in Spring, 1971.

COUNTRY	RESERVES: Oil (MB)	RESERVES: Gas (BCF)	WELLS: Producing oil 7-1-70	WELLS: Drilling 12-1-70	OIL PRODUCTION: Estimated 1970 (MB/D)	OIL PRODUCTION: % change from 1969	No. refs.	REFINING Capacity (MB/D) January 1, 1971: Crude	Cracking	Reforming
MIDDLE EAST										
Abu Dhabi	11,800,000	9,500	94	6	640.9	6.6	---	---	---	---
Bahrain	634,000	5,000	232	1	76.8	1.1	1	216.0	59.1	16.0
Dubai	983,000	750	11	2	77.9	---	---	---	---	---
Iran	70,000,000	214,000	266	17	3,753.2	14.2	5	632.8	52.0	81.5
Iraq	32,000,000	18,500	113	2	1,517.8	-0.6	6	102.9	14.0	8.0
Israel	12,900	72	32	2	93.0*	77.7	1	132.0	27.0	16.0
Jordan	---	---	---	1	---	---	1	15.6	1,350.0	8.7
Kuwait	67,100,000	38,000	741	1	2,743.8	9.1	3	504.0	---	13.6
Lebanon	---	---	---	---	---	---	2	54.5	---	7.6
Neutral Zone	25,700,000	8,000	450	2	485.6	7.5	2	80.0	---	---
Oman	1,700,000	2,000	62	2	336.1	7.1	---	---	---	---
Qatar	4,300,000	8,000	69	1	353.9	0.3	1	68.0	---	---
Saudi Arabia	128,500,000	49,500	423	5	3,437.5	19.9	2	906.0	---	47.5
South Yemen (Aden)	---	---	---	1	---	---	1	178.0	---	10.0
Syria	1,200,000	750	90	8	50.0	4.1	1	59.0	20.0	3.5
Turkey	645,000	190	279	4	68.0	-0.9	4	290.0	23.5	30.1
TOTAL MIDDLE EAST	344,574,900	354,262	2,862	55	13,634.5	12.3	30	3,171.7	196.9	234.6

*Includes captured Sinai fields.

TABLE 14 (CONT'D.)

WORLD RESERVES AND PRODUCTION—1970

COUNTRY	RESERVES		WELLS		OIL PRODUCTION			REFINING Capacity (MB/D) January 1, 1971		
	Oil (MB)	Gas (BCF)	Producing oil 7-1-70	Drilling 12-1-70	Estimated 1970 (MB/D)	% change from 1969	No. refs.	Crude	Cracking	Reforming
AFRICA										
Algeria	30,000,000*	141,000	775	25	984.0	275.0	2	48.3	---	13.0
Angola (incl. Cabinda)	500,000	1,000	141	4	110.0	131.6	1	14.0	---	2.0
Congo-Brazzaville	3,600	---	5	1	0.5	-37.5	1	33.0	---	3.0
Congo-Kinshasa	1,000†	---	---	1	---	---	---	---	---	---
Dahomey	1,000†	---	---	1	---	---	---	---	---	---
Egypt	4,500,000	5,000	332	9	328.5	35.9	3	175.0	5.0	15.2
Ethiopia	---	---	---	---	---	---	1	13.4	---	1.8
Gabon	700,000	7,000	100	4	106.0	7.5	1	17.2	7.9	1.5
Ghana	1,000†	---	---	2	---	---	1	28.0	---	6.5
Ivory Coast	---	---	---	---	---	---	1	19.0	---	3.0
Kenya	---	---	---	1	---	---	1	50.5	---	4.6
Liberia	---	---	---	---	---	---	1	10.0	---	2.0
Libya	29,200,000	30,000	1,083	13	3,385.0	11.0	1	9.5	---	2.2
Malagasay	---	---	---	2	---	---	1	11.9	---	2.0
Morocco	920	16	52	1	1.0	-28.5	2	35.0	4.0	7.7
Mozambique	---	---	---	1	---	---	1	47.0	---	8.5
Nigeria	9,300,000	6,000	364	18	1,000.0	93.0	1	55.0	---	4.6
Rhodesia	---	---	---	1	---	---	---	---	---	---
Senegal	---	---	---	---	---	---	1	12.0	---	2.0
Sierra Leone	---	---	---	---	---	---	1	10.0	---	---
Sudan	---	---	---	---	---	---	1	20.0	---	2.0
Tanzania	---	---	---	---	---	---	1	30.6	---	7.7
Tunisia	550,000	1,000	46	3	88.0	10.2	1	22.5	---	3.3
Union of South Africa	---	500†	---	4	---	---	5	262.9	73.5	59.4
TOTAL AFRICA	74,757,520	191,516	2,898	91	6,003.0	36.5	29	924.9	90.4	152.1

*Government estimate.
†Oil or gas discovered but not yet developed.

WESTERN HEMISPHERE										
Argentina	4,500,000	8,800	5,400	26	391.0	15.0	14	456.2	232.0	18.9
Bahamas	---	---	---	1	---	---	1	250.0	---	---
Barbados	750*	---	---	1	---	---	1	3.0	---	---
Bolivia	225,000	5,000	171	10	13.2	-70.9	5	23.1	---	---
Brazil	850,000	6,000	1,015	28	157.6	-12.2	10	504.6	92.5	39.5
British West Indies	---	---	---	1	---	---	1	16.0	---	2.0
Chile	125,000	2,000	380	8	38.3	3.0	2	111.0	32.5	10.0
Colombia	1,675,000	2,800	2,171	5	222.0	6.7	5	137.6	76.0	---
Costa Rica	---	---	---	---	---	---	1	8.0	3.0	1.2
Cuba	14,000	---	15	12	2.5	---	3	93.0	24.0	15.0
Ecuador	750,000	5,000	708	7	4.0	-18.4	1	35.3	7.0	1.0
El Salvador	---	---	---	---	---	---	1	13.0	---	2.0
Guatemala	---	---	---	---	---	---	2	26.0	---	6.0
Honduras	500*	---	---	---	---	---	1	14.0	---	1.6
Jamaica	---	---	---	1	---	---	1	36.0	---	3.2
Mexico	3,200,000	10,000	3,127	80	427.4	5.5	6	574.2	102.0	94.2
Netherlands Antilles	---	---	---	---	---	---	2	790.0	497.0	22.0
Nicaragua	---	---	---	1	---	---	1	22.0	---	4.3
Panama	---	---	---	---	---	---	1	75.0	22.4	7.5
Paraguay	---	---	---	---	---	---	1	5.0	---	---
Peru	270,000	3,000	2,500	5	72.0	20.0	5	91.5	22.7	1.8
Puerto Rico	---	---	---	---	---	---	2	140.0	75.5	88.0
Trinidad and Tobago	575,000	3,500	3,133	6	141.0	-13.0	3	438.0	26.5	27.0
Uruguay	---	---	---	---	---	---	1	40.0	10.0	3.0
Venezuela	14,000,000	27,000	9,364	14	3,690.0	3.3	12	1,526.1	157.5	23.1
Virgin Islands	---	---	---	---	---	---	1	250.0	---	15.0
United States	37,012,640	265,000	640,760	1,065	9,506.5	3.6	262	13,293.0	8,514.0	3,065.0
Canada	10,750,000	60,451	23,675	141	1,277.5	15.4	41	1,450.0	735.0	245.0
TOTAL W. HEMISPHERE	73,947,890	398,551	692,419	1,411	15,943.0	4.2	386	20,421.6	10,540.2	3,696.0

*Oil or gas discovered but not yet developed.

TOTAL FREE WORLD	511,397,458	1,148,390	708,622	1,770	37,344.0	10.3	702	45,757.0	13,242.0	6,752.0
COMMUNIST WORLD	100,000,000*	440,000†	---	---	7,566.0	7.4	---	---	---	---
TOTAL WORLD	611,397,458	1,588,390	---	---	44,910.0	16.7	---	---	---	---

*Including Russia 77 billion, Red China 20 billion, Hungary 1 billion, others 2 billion.
†Including Russia 426 trillion, Red China 4 trillion, Hungary 3.5 trillion, Poland 5 trillion.

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New refineries may be more highly specialized. Modern technology allows a refinery to convert nearly all of the crude into gasoline and middle-of-the-barrel products, or conversely to manufacture primarily low-sulfur fuel oil and naphtha. In the past, the trend of gasoline octane quality was generally upward to accommodate increasingly higher compression ratio automobile engines. Today, there are many factors combining to upset the old accepted principles. Superimposed on normal demand growth are influences that promote uncertainty as to how much gasoline to provide for and as to what quality. The growing demand for accessories has added considerably to fuel consumption in today's car population.

Further degradation of fuel economy may be expected from add-on, anti-pollution devices required by laws and regulations. Offsetting effects are projected resulting from the volume of gasoline required to promote the greater use of mass transit, and smaller cars, restrictive regulation on the use of automobiles in certain areas and threat of high gasoline taxes. There is also the concurrent regulatory requirement to restrict the lead content of gasolines to accommodate anti-pollution devices. This tends to lessen the effective capacity of existing facilities to produce gasoline pools of higher clear octane quality.

Similarly, substantial reduction of the sulfur content of gasolines from the present low levels will entail new processing and sulfur removal facilities. The effect will be higher capital investment if this trend continues, since gasoline represents a very substantial part of refinery production.

If all of the factors were well defined, the net effect could be projected with reasonable certainty, and planning could proceed; but the development of requirements on a piecemeal basis has prompted the industry to move slowly so as to avoid making premature decisions.

These factors are illustrative of some of the current influences exerted by regulatory restrictions on what must be manufactured in the refinery. In addition to changes in gasoline requirements, there is also the somewhat more normal transition of energy users from one type of fuel to another. The pressure of environmental restraints requires the use of low-sulfur petroleum oils in place of fuels whose emissions are more costly to control. The starting point in the new refinery planning process must certainly be a good evaluation of the type and quality of products required to fill the projected demand in the marketplace from available crude oils. This becomes increasingly difficult with the increased involvement of local, state and Federal Government (through regulatory agencies) in the energy field.

Current and future refineries must meet increasingly stringent requirements, especially in the sulfur contents of fuels. The precise distribution of demand for products of different quality (with regard to sulfur) is still largely undefined since the environmental laws in the various political subdivisions vary considerably. Thus a Priority-1 Air Quality Control Region (for sulfur oxides) may require the marketing of residual fuel of not more than 0.3 percent sulfur in one state, while in another there may be no stated restrictions on sulfur in fuel. In some areas, the regulations are based on the quality of stack emissions rather than the sulfur content of fuel. This places the onus of meeting the regulations upon the consumer, who must employ an adequate technology, and may at times aggravate environmental problems in other waste disposal areas in the process. It stands to reason, however, that even in these circumstances, the consumer may seek to meet the emission requirements through the grade of fuel bought, if the economics of doing so are favorable. It is evident that this places the refinery in a position of uncertainty as to what the market may require. The prudent course in the initial phases of the pattern envolving over the last few years has been to wait until all the facts were in before committing to large scale expansion, particularly since investments are large. This may well account in part, for the present dearth of new refinery construction.

Table 61 in Appendix F, taken from the report prepared for the Environmental Protection Agency's Office of Air Programs by the Mitre Corporation, entitled *Analysis of Final State Implementation Plans--Rules and Regulations*, shows East Coast residual fuel oil anticipated sulfur specifications. It should be noted, however, that the EPA may impose more stringent restrictions if the regulations enacted by the states fail to achieve and maintain ambient air quality objectives. Until the target dates for primary and secondary objectives have been passed, there will continue to be uncertainty as to whether product specifications can be considered firm.

The uncertainties of environmental matters are made especially difficult by the fact that very few clean-up processes (such as stack gas treatment) have been commercially proven. Many processes have not even had a real commercial trial, much less operating experience of a year or more. In addition, many of the processes may require vast amounts of limestone and dolomite over a period of years. These materials neutralize or precipitate out sulfur compounds that must then be disposed of. If such a process is used, many acres of land must be provided to accumulate the waste. Thus, a solid waste problem may be substituted for an air pollution problem if such a process has widespread use.

At present, many companies are trying to come up with better technology to remove sulfur oxides and particulates from stack gases, while at the same time being concerned about whether some entirely different process will have to be installed to meet the requirements for nitrogen oxide removal. There is concern that all the money being spent on sulfur compounds will have been in vain because of new requirements and other changes in regulations. The current state of the art for desulfurization of stack gas is summarized in Appendix F, Table 62. The processes described embody some 20 techniques to reduce sulfur in final gas effluents, representative of more than 50 identifiable processes.* Table 63 in Appendix F shows a supplementary API tabulation which contains information on some additional proprietary processes.† To date, all of these processes which would facilitate the handling of high-sulfur fuels while meeting environmental requirements must be considered to be under development.

The competing technology (catalytic desulfurization) has been in practice for the past two decades on light and intermediate boiling range distillate fuels. To meet the emerging environmental regulations, in the absence of adequate stack gas treating technology, and assuming the availability of a preponderance of high-sulfur import crudes, the refiner may want to consider the desulfurization of residual fuels as one of the available alternatives.

Economic and adequate residual desulfurization is still in early development. In this process, the liquid hydrocarbon is contacted with hydrogen in the presence of catalysts under conditions of high pressure and temperature. Many reactions can and do occur. Each process specializes in accomplishing a specific type of treatment. For instance, some hydrocracking will occur. This reaction is the result of cracking larger molecules to smaller ones and adding hydrogen at the same time. It results in the formation of materials of lower boiling range, lower viscosity and, in general, lower color level. Such materials vary from methane (natural gas) and other light and liquefied petroleum gases to gasoline and fuel oils. These products are more valuable than the original heavy black residual feedstock; however, they result in the usage of large quantities of hydrogen and require costly catalysts. Production of very low-sulfur fuels by residual desulfurization is very expensive because of the above features.

The desulfurization of fuel may be either by a direct process in which the residual material (from either a preliminary atmospheric or vacuum distillation) is treated in a direct, or an indirect process in which distillate fractions of the residue are treated and are blended back into the residues. It is generally accepted that desulfurization of fractions of the crude containing more than about 150 parts per million (ppm) of heavy metals is uneconomic because of deposition of metals on the catalyst in the process. Hence, direct desulfurization is only adopted when (1) the final fuel oil must be low in sulfur or (2) the feedstock contains a very large amount of sulfur and the residue to be desulfurized contains a very large amount of sulfur and the residue to be desulfurized contains less than about 150 ppm of heavy metals.

A number of processes are on the market which can reach a sulfur level of 1 percent or less on the light kerosine and heavier

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* Hyne, Dr. J. B., "Methods for Desulfurization of Effluent Gas Streams," *Oil and Gas Journal*, August 28, 1972.

† American Petroleum Institute's Division of Refining, "Summary of Desulfurization Processes for Flue Gas and Claus Unit Tail Gas." Paper presented at the 37th Midyear Meeting of the API's Division of Refining, New York, May 9, 1972.

fuel oil when charging a Kuwait type crude oil. When distillate fuels are combined with the heavy fuel, the sulfur level may be less than 0.3 percent. Kuwait crude oil is usually chosen for pilot work because it has a fairly high-sulfur content and the content of heavy metals is comparatively low. Because the heavy metals--primarily nickel and vanadium--are deposited on the catalyst and gradually destroy its activity, they determine the size and number of reactors required and limit the length of runs between catalyst replacements. Such factors weigh heavily in the overall cost of residual fuel oil desulfurization.

If the residue is very high in metals, preliminary processing steps such as coking may be necessary before desulfurization. This often creates the concomitant problem of disposition of high-sulfur coke. There is continuing research in this field, including exploration of the use of pretreating steps to remove metals, catalyst development and modification of operating conditions; but the present state of the art is limited by the factors noted. Table 64 in Appendix F shows average metals in major petroleum products. Table 65 shows the sulfur and nickel plus vanadium content of specific Middle East and reduced crudes. Table 66 shows processing sequences for the most economical production of low-sulfur fuel oil.*

Today's technical literature contains many references to desulfurization technology. One especially appropriate source is "A Special Report--Hydrodesulfurization Technology Takes on the Sulfur Challenge," by Leo Aalund, in the September 11, 1972, *Oil and Gas Journal.* The report gives updated evaluation of commercially available processes for direct and indirect desulfurization of fuel oils and distillates. A summary of the processes covered is shown in Table 67, Appendix F.

In the foregoing evaluation, the anticipated growth in the demand for petroleum products by 1985 has been discussed broadly. The factors that make it difficult to conduct effective planning--uncertainty as to required product quality; shortage of environmentally desirable crude oils; changing regulatory requirements affecting both quality and demand for specific products; and the growing restrictions regarding location, makeup and operation of new facilities--have been mentioned as inhibiting factors discouraging the short-term provision of new refining capacity. The special problems of small refineries have been mentioned briefly, as these could increase the need for new capacity due to accelerated obsolescence and phasing out of unprofitable plants.

In the final analysis, the individual crude supply, market requirements, environmental factors and company logistics will determine the location and type of facilities built. Only when the combined factors give a *favorable economic picture* will new refineries, designed to meet the ever-growing demands of a mushrooming society, be planned, constructed and put into operation. Only when more of the unknowns in the equation are defined, and a cohesive national energy policy is adopted and implemented, can this be done with certainty so that the country's needs for energy from petroleum-related products will be satisfied in the amount and at the time needed.

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* Nelson, W. L., *Oil and Gas Journal*, July 31, 1972.

REFINERY REQUIREMENTS RESPONSIVE TO ENVIRONMENTAL NEEDS

A high degree of industrialization, a growing population and a continued concentration of people in urban areas are three obvious characteristics of the American society in the early 1970's. They are also factors which have combined to make pollution of the environment a major problem of our time. Americans, who have long taken for granted the increased material benefits derived from higher rates of energy consumption, are now becoming aware of the potential conflict between energy requirements and environmental goals. Both high energy consumption rates and satisfactory maintenance of environmental standards are possible, but only through dealing effectively with the total environmental, social and economic system.

The petroleum industry, in particular, is caught up in the energy-environment conflict because of its special role in the overall energy picture. Demands for petroleum products often fluctuate widely and have of late increased alarmingly, due to the fact that they can supplement the shortfall in any other energy sector of our economy. Oil in effect, acts as a "swing" fuel. Production, transportation and refining of petroleum, as with other forms of energy, present special environmental conflicts.

The petroleum industry has been diligent in attempting to define and to take steps in correcting problems that pose environmental hazards. The industry's concern has been well-documented in a study made by the National Petroleum Council entitled, *Environmental Conservation--The Oil and Gas Industries*, which was released in 1971. Concurrently, the dwindling supplies of domestic energy resources have been receiving increased attention, not only from the petroleum industry, but also from the government. This matter has been examined in detail by the National Petroleum Council's U.S. Energy Outlook study released in December 1972.

The energy study, supplemented by other reputable investigations, has conclusively shown that our Nation will become increasingly dependent on imports of crude oil and/or finished products. Since importation of finished products means exporting employment, with its increased burden upon an already unfavorable balance of trade, one conclusion which many have reached is that importing crude is to be preferred over importing finished products.

The desire to minimize product imports from abroad focuses attention upon the shortage of domestic refinery capacity which now exists, and which projections indicate will become more acute. This shortage is dramatized by the fact that the University of Texas, located in the heart of our Nation's crude supply, postponed opening its second semester in 1973 by one week because of nonavailability of fuel oil. Whereas unacceptable returns on investments have had an inhibiting economic influence on new refining construction, as addressed in other sections of this report, environmental factors have played a significant role in contributing to refinery capacity shortages existing in our country.

The principal environmental factors which have had inhibiting influences on the expansion of domestic refinery capacity are:

- Availability of crude oil for refinery charge stocks
- Availability of deepwater port facilities
- Availability of refinery sites
- Uncertainties regarding technical and economic problems, especially those requiring quality of air and water effluent from refineries
- Uncertainties regarding the present and proposed environmental regulations which refer to quality of refined products, particularly gasoline and fuel oils
- Uncertainties regarding the government and/or environmental agencies approval time and the necessary time to plan, engineer and construct new or modified refinery facilities.

Availability of Crude Oil

Basic to any refinery construction is the assurance of availability of suitable charge stock of known quality and assured stability of supply for a reasonable period of time. Well-meaning but perhaps overly zealous citizen groups have interfered with supplies of available or potentially available crude oil to refineries.

Probably this "interference" has manifested itself primarily in the availability of domestic crude oil. For example, reserves of crude oil in the North Slope of Alaska have been estimated to be more than 10 billion barrels, a volume which is equivalent to about one-third of the known reserves of the lower 48 states. Billions of dollars of idle capital have resulted from citizen court actions and other delays in obtaining permission to produce and move this oil to market through a new pipeline. All this has been done in the name of environmental conservation, even though the pipeline would be built and operated within strict environmental limitations.

These dormant reserves have not only drained money from possible uses in other ventures, such as expanding refinery capacity, but have increased our Nation's dependence on imports from outside of the United States, with attendant penalties on national security and balance of trade. The Nation cannot afford to allow such resources to remain unused indefinitely. Yet even under the most optimistic predictions, it will be several more years before supplies of this high quality crude oil move from the Alaskan North Slope to domestic refineries.

Surveys have indicated the potential for large quantities of crude oil and natural gas lying beneath offshore waters surrounding our continent. However, many areas of the continental shelf of the United States remain undeveloped or underdeveloped because of environmental concerns. As detailed in earlier studies, incidents of blow-outs, though widely publicized, have been extremely rare compared to the number of offshore wells drilled. These few unfortunate incidents have caused the industry to further emphasize the necessity for more vigilant protective and preventive measures which are now commonly being applied to new offshore developments. There is a need and an increasingly important justification for restructuring the rigid constraints which are now slowing or preventing development of offshore oil and gas potential.

Availability of Deepwater Port Facilities

While domestic reserves need to be developed to their fullest, the need will still exist for supplemental quantities of crude oil from other countries. The safest, most efficient and economical method of transporting these needed volumes is through the use of very large crude carriers (VLCC's), delivering to refinery centers. Effective use of VLCC's will require the construction of deepwater ports, located just offshore, with pipelines delivering supplies from these superports to refineries located onshore.

All of the U.S. unloading ports are now located at the shorelines, in relatively shallow water, and are unable to accommodate VLCC's. Documented evidence shows that most spills from tankers occur at or near these congested unloading ports. Such spills adjacent to land areas are difficult to clean up before potential problems with coastline contamination develop. Superports offer a number of environmental advantages, such as minimization of occurrences of accidental spills and their effects on shorelines, less frequent ship movements and greater maneuvering ability at remote distances from land. Likewise, supertankers with compartmented cargoes and with highly trained crews, along with sophisticated new navigation equipment and safety developments, offer environmental advantages over more frequent movements of older, smaller vessels.

Unfortunately, despite the recommendations of various authorities and informed groups, such as the Corps of Engineers, construction of superports (and consequently, supertankers) has been delayed, generally because of resistance of state governments off whose shores the ports would be located. Positive action on the part of the Federal Government is needed to formulate policy whereby the goals of the coastal states and the welfare of the Nation's population as a whole might mesh in a mutually acceptable solution to this pressing need.

Availability of Refinery Sites

In addition to the obvious need for available land, two key factors are important in selecting refinery locations: (1) convenience of location and (2) a means of supply for crude oil and, in some cases, natural gas. In general, this means a location adjacent to or near a deepwater port and a location near marketing centers for refined products.

The requirements relating to land use, construction and operating permits and other environmental considerations have seriously limited and delayed site selection for new plants. Environmental issues and restrictive emission requirements have delayed or actually prevented new refining construction. Of more concern than the difficulty of complying with these requirements are the instances where proposed refinery construction--after complete compliance with federal, state and local requirements--is halted by citizen group court action.

Expansion of existing plants generally presents fewer problems than construction of new plants, at least as far as delays relating to environmental issues are concerned. However, major modification of existing plants will, in general, require meeting new source standards and will involve the same red-tape delays as now exist for new plant construction. Expansion of existing plants is also prohibited in some cases by land availability. Many existing plants were built with obsolete technology, making them economically unattractive to expand as compared to building completely new facilities.

Despite the rigorous emission standards for both water and air that refineries must meet now and in the future, resistance to constructing plants in a given location is still encountered in many areas of the country. It is believed that as the public becomes more aware of the excellent performance of modern refineries from a pollution control standpoint, such resistance toward plant location will disappear.

Environmental Considerations

The situation with regard to air and water quality from refineries is similar in that the national contribution of refineries is not large. Among the many steps the petroleum industry has taken to reduce pollution in the areas of air, water and noise and light are:

- Air Pollution Control

  --Greater use of low-sulfur fuels and sulfur recovery plants, increased capacity to desulfurize products, development of new processes for removing sulfur oxides from stack gases

  --Control of hydrocarbon emissions and odors by floating roofs on storage tanks, mechanical seals on pumps, closed systems to recover vented vapors

  --Reduction of particulate emissions by smoke controls, electrostatic precipitators and cyclone separators

--Special furnaces to burn gases containing carbon monoxide

--Air quality monitoring instruments.

- Water Pollution Control

  --Expansion of water reuse systems and increased use of air cooling

  --Multiple-stage effluent treating to remove oil and other wastes, biological treatment to remove organic material which might be harmful to marine life

  --Designing and remodeling of facilities to minimize the possibility of oil spillage, closer surveillance of oil transfer operations.

- Noise and Light Pollution Control

  --Use of silencers and other devices to reduce noise emissions

  --Use of low-level, shielded and smokeless incinerators to reduce smoke, glare and noise from flares.

Future new refineries will incorporate many of the current emission and effluent control systems together with newly developed processes. Environmental studies at the site will begin before construction to establish and document the preconstruction conditions. These studies will also serve to anticipate any potential adverse impact on the facilities and to permit revisions of the design to minimize or eliminate this impact. These studies will be continued through the initial period of operation to document the suitability of the pollution control facilities as they are designed. Where appropriate, buffer zones will be provided to isolate operating units from surrounding residential or recreational areas. Peripheral landscaping will be used to improve the refinery's appearance.

Existing refineries either are already in conformance with ambient air quality standards or will be under legally binding schedules for installing the necessary equipment. Further, rational evaluations have shown that many of the present refineries can be expanded and the necessary new refineries can be built while achieving a satisfactorily clean environment. In order to meet the goal of expanded energy supply, it is essential that the emission standards imposed be realistic. As zero emission levels are approached, costs and operating problems tend to become excessive, often without measurable benefit to the environment and often with attendant waste of resources.

The need for protection of the environment has received a great deal of attention--measured by actual investment--from the petroleum industry. The results of a recent API survey show that the industry is currently spending an average of $3.3 million daily to protect the environment. Estimated figures for 1972 indicate that environmental expenditures will total $1.2 billion, of which more than $1.0 billion is committed for air and water conservation. The remainder goes toward land and restoration, solid waste disposal and noise control programs. This expenditure is approximately $0.25 per barrel of crude refined.

In considering air and water effluent control from refineries, a review of current national goals, along with government policies and regulations, should assist in understanding the present-day situation.

Water Quality

The national policy toward water quality, as declared by Congress in the Water Quality Standards Act of 1965, was to recognize, preserve and protect the primary responsibilities and rights of the *states* in preventing and controlling water pollution. However, recently enacted legislation may require further definition of the state's role in implementing water quality standards. In October 1972, Congress passed legislation over a Presidential veto containing comprehensive amendments to the Federal Water Pollution Act. President Nixon had vetoed the bill (S-2770) because of what he termed "its unconscionable price tag" of $24.6 billion which dwarfed the original administration request for $6 billion. The major provisions of the new bill include:

- A July 1, 1977, deadline for installation of "the best practicable control technology" currently available for industrial effluents
- A July 1983, deadline for the use of "best available technology economically achievable" for industrial sources
- The development of national standards for minimizing pollution in effluents from industrial plants falling in 27 different categories
- The addition of "hazardous materials" to the section of the law prohibiting the discharge of harmful quantities of oil, and the extension of liability for the cleanup of such discharges
- Creation of a comprehensive national permit program for controlling the discharge of pollutants
- Declaration of the national goal to be the elimination of discharges of pollutants into navigable waters by 1985.

The new Federal Water Pollution Control Act Amendments of 1972 provide the above requirements as a minimum for industrial plants. However, the receiving water quality will prevail. The Environmental Protection Agency has been obtaining information to be used in establishing levels of "best practicable control technology" for various categories of industrial plants including petroleum refineries.

The definition of "best practicable control technology" should be based on control methods that are available and economically practical and proven through full-scale application over a considerable period of time. "Best available technology" is subject to changes in definition at any time, based on changes in techniques and economics. Therefore, industry is forced to continually aim at a moving target.

An Executive Order in December 1970, pursuant to the Refuse Act of 1899, required all industries discharging into navigable waters to apply for a federal permit. The recent legislation would provide a new permit program, not based on the Refuse Act, in which states can issue discharge permits once the state program is approved by the EPA. Federal law also prohibits the discharge of oil and hazardous materials in harmful quantities into U.S. navigable waters, adjoining shorelines, or the contiguous zone (3 to 12 miles offshore) by vessels, onshore facilities or offshore facilities. The Coast Guard recently promulgated regulations on pollution prevention which will control and regulate activities and facilities at all marine installations.

Air Quality

As provided in the Clean Air Act Amendments of 1970, the EPA has established performance standards in terms of atmospheric emissions for new and modified plants. Standards for new facilities in only five industrial categories have been established to date. New source performance standards for selected refinery facilities have been developed by the EPA.

Like water quality standards, air quality control, too, is for the most part a function of state governments, often acting cooperatively through designated air quality control regions. State standards can be no more lenient, but may be more restrictive than the federal ambient air quality criteria dictated to be required for the protection of health and welfare. Maintenance of air quality requires the control of specific emissions as well as the setting of standards for ambient air, since the latter would be impossible to enforce alone.

Nationwide, the contribution of oil refineries to atmospheric pollution is relatively small (see Table 15). In some local situations, however, control of refinery emissions is required and can be achieved (see Table 16).

In assessing the possible effects of government environmental conservation policy on U.S. refinery capacity, it is well to consider some fundamentals--namely, the sources, abundance and fate of several pollutants which may tend to build up in the atmosphere --and the status of control technology.

TABLE 15

ESTIMATED NATIONWIDE EMISSIONS—1969*
(Million Tons per Year)

	Sulfur Oxides	Particulates	Carbon Monoxide	Hydro-carbons	Nitrogen Oxides
Petroleum Refining	2.0	0.1	2.6	2.3	< 0.1
Total Man-made Emissions	33.4	35.2	151.4	37.4	23.8

* Final Report of the Ad Hoc Committee, prepared for the U.S. Office of Science and Technology. *Cumulative Regulatory Effects on the Cost of Automotive Transportation (RECAT),* Washington, D. C., (February 28, 1972).

TABLE 16

REFINERY AIR CONTAMINANT EMISSIONS
LOS ANGELES COUNTY—JANUARY 1971*
(Tons per Day)

	Sulfur Oxides	Particulates	Carbon Monoxide	Hydro-carbons	Nitrogen Oxides
Without Control Program	1,320	15	1,635	1,495	130
With Control Program	55	10	5	295	95

* *Profile of Air Pollution Control* (Air Pollution Control District, County of Los Angeles, Calif., 1971).

Sulfur Dioxide (SO_2)

A product of fossil-fuel combustion, sulfur dioxide has a relatively short residence time in the atmosphere--usually a few days, or at most a few weeks. Consequently, global background concentrations are quite low--on the order of a few parts per billion. Sulfur dioxide pollution is primarily an urban problem, with concentrations and durations of exposure in some parts of major metropolitan areas exceeding, by a substantial margin, federal air quality criteria for health.

Standards presently set for most parts of the country will require a high degree of emission control. All of the required technology is not generally available, but both research and demonstration projects are under way. Control of sulfur dioxide emissions is accomplished by two types of regulation. One establishes legal maximum limits on the sulfur content of fuels, and the second establishes limits on the amount of sulfur that may be emitted into the atmosphere at a given rate of energy usage. Currently, sulfur dioxide limits are usually met by using lower sulfur fuels which are available in limited amounts.

Much work is being done on processes to desulfurize stack gases, and several are being evaluated in demonstration size units. Stack gas desulfurization processes would permit large plants to use high-sulfur fuels and still meet the sulfur dioxide emission limits. A number of engineering problems and higher than expected operation and maintenance costs have been encountered in the tests made to date. These processes are not likely to be in wide use in time to meet existing and proposed environmental targets. Establishing regulations which exceed the capability of available technology may increase research and development efforts but, at the same time, the growth of the industry may be seriously affected.

Concern over air pollution would be expected to accelerate the trend toward nuclear power generating facilities, despite an expected increase in costs for equipment to control thermal pollution of lakes and streams. However, concern over atmospheric effects and other potential hazards continues to slow development.

Carbon Monoxide (CO)

Carbon monoxide, a toxic substance resulting from the incomplete combustion of fossil fuels, has been encountered in concentrations as high as 50 to 100 parts per million (PPM) in urban atmospheres, although the estimated average global concentration is only about 0.1 PPM. Ambient air quality standards have been established at a maximum of 9 PPM for an 8 hour average, and 35 PPM maximum for a 1 hour value. These values are not to be exceeded more than once a year.

Total worldwide annual CO emissions from combustion sources have been estimated at 304 million tons, with automobiles accounting for 84 percent of this total. Coal-burning installations are the second largest source of CO from combustion. Recent studies at the Argonne National Laboratories, sponsored by the Coordinating Research Council, concluded that natural emissions of carbon monoxide are about 10 times the man-made CO emission rates. Modern refineries have special furnaces to burn gases containing carbon monoxide, converting it to carbon dioxide.

Other Contaminants

Refiners have taken positive steps to reduce hydrocarbon emissions and odors by installing floating roofs and vapor recovery systems on storage tanks and loading facilities, with mechanical seals on pumps, and closed systems to recover other vented vapors. Particulate emissions are reduced by smoke control devices--electrostatic precipitators and cyclone separators. Bag filters have also found some usage.

Expenditures which will be required to bring air and water effluent from refineries within the rigid limits of the new air and water acts will be sizable. Costs are expected to increase even further as new and more rigid standards emerge. Also, since the "floating target" requires use of the best technology available, costs will also increase as the industry moves to purchase new technological improvements as they develop.

Product Quality

Uncertainties regarding the quality requirements of refined products in relation to moving emission standards have been a contributing factor in delaying decisions as to the type and extent of refinery expansions. The two major areas of product quality uncertainties surround the maximum sulfur level of fuel oils and the octane level of motor gasoline, together with lead alkyl usage for the latter product. The extent of product quality changes which may become necessary to comply with government regulations to be promulgated have not been fully defined. This certainly has delayed and is continuing to delay final selection of refinery processes.

Sulfur in Fuels

As stated earlier, air quality controls on sulfur dioxide emissions often translate into sulfur limits on fuels. Most states impose individual standards on allowable sulfur content of fuel oils, which is generally a 1.0 percent maximum in Priority 1 areas (ambient air contaminant level higher than national primary standard). However, some of these areas (such as New York City, Toledo, New Jersey, etc.) have more restrictive standards which will require fuels as low as 0.3 percent sulfur. Product distribution patterns might then force production of the lowest specification product in order to service all accounts.

Direct desulfurization of high-sulfur residual fuels can presently be accomplished with reasonable economics only on certain low-metal content residual fuels. Consequently, the volume of low-sulfur product obtained from this process is limited.

Relatively mild desulfurization may cost on the order of $0.40 per barrel. Other heavy stocks requiring more severe hydrogen treating or other expensive processing to meet low-sulfur limits may cost from $0.60 to $1.00 or more per barrel on an equivalent heating value basis.

Low-sulfur residual fuels are also obtained by topping naturally occurring low-sulfur crudes. Residual fuels produced from this type of operation generally range in 0.3 to 1.0 percent sulfur level, depending on crude source. Domestic crudes are largely of low-sulfur type, but the supply is sorely limited. Foreign supply sources of this type crude, principally North and West Africa and Indonesia, are relatively small, and worldwide competition for them is increasing rapidly.

The most common method of obtaining low-sulfur (1.0 percent) fuels is by blending high-sulfur residual fuels with desulfurized low-sulfur vacuum gas oil. This technique is being used to supply most of the low-sulfur fuel for the East Coast markets. Desulfurization of the overhead from vacuum distillation of reduced crude can produce fuels having a sulfur content as low as 0.3 percent; however, the use of only this portion, with no back blending of resid (vacuum bottoms), would greatly reduce the volume of 1.0 percent sulfur fuel, which is currently in short supply.

Motor Gasoline Quality

The 1970 Clean Air Act Amendments provide for registration of fuels and fuel additives and authorize the Environmental Protection Agency to limit the use of additives if such additives either prevent emission control systems from operating effectively to meet the emission standards, or are detrimental to the health and welfare of citizens. EPA action on the control fuels or fuel additives preempts state or local government action in this area.

On February 23, 1972, the Environmental Protection Agency published proposed regulations for fuels and fuel additives in the *Federal Register*. These regulations were finalized on January 10, 1973, when the EPA published in the *Federal Register* requirements on the general availability of unleaded gasoline by July 1, 1974, containing not more than 0.05 gram of lead and not more than 0.005 gram of phosphorous per gallon, and having a minimum Research Octane Number (RON) of 91. This regulation provided for the quarterly averaging of the lead content of leaded grades of gasoline for each refinery and for a reduction of the 91 research octane level of the unleaded grade for altitudes above 2,000 feet. The EPA also proposed that existing grades of leaded gasoline be limited to a maximum of 2.0 grams of lead per gallon beginning January 1, 1975, with the permissible maximum declining to 1.25 grams per gallon by January 1, 1978.*

Numerous state and local political units have passed legislation even more restrictive than the EPA proposed. New York City's current regulations require a complete phase-out of all lead. Also, certain counties in California adopted regulations that would phase out all lead in gasoline by 1976, although court action has stopped these regulations from being put into effect. Buffalo and Jamestown, New York, and the state of Maryland have adopted separate and more restrictive lead reduction regulations. Emissions from internal combustion engines include carbon monoxide, nitrogen oxides, hydrocarbon and particulate matter. All except particulates are limited by federal regulations. California has separate state regulations.

* On December 6, 1973, the EPA published regulations stating that the maximum 3 month average lead content of the total gasoline pool at any refinery will be limited to 1.7 grams per gallon by January 1, 1975, and phased down on a yearly basis to 0.5 grams per gallon by January 1, 1979.

According to present internal combustion engine technology, three general types of approach exist for the reduction of nitrogen oxides, hydrocarbons and carbon monoxide in automobile exhaust. One approach would install a dual-catalyst system in which one catalyst reduces nitrogen oxides (NO_x) to nitrogen and by-products, while the second catalyst converts hydrocarbons and CO to H_2O and CO_2. However, even the best of these catalyst so far developed are deactivated by lead. Unleaded gasoline, therefore, would be a required fuel for use with such a system. Certain manufacturers claim recent developments which may result in catalysts which are not deactivated by lead.

A second approach would consist of a single-catalyst system to convert the hydrocarbon and CO emissions to H_2O and CO_2, with recirculation of a portion of the exhaust gas (EGR) to control the formation of NO_x. These control systems will result in some decrease in fuel efficiency. As a result, increased crude oil consumption will be necessary in order to supply the added fuel required for a given distance traveled.

A third approach would involve the use of thermal rather than catalytic reactors, and if proven feasible, might permit continued use of leaded gasoline. The magnitude of the increased demand for gasoline as a result of the lower fuel utilization efficiency will depend on the mode of operation selected. However, an estimated 5 to 10 percent increase in crude requirements as a result of such new emission control devices is anticipated.

Based on auto industry testimony, the EPA administrator recently adopted new interim auto emission limits for 1975, while requiring the original 1975 limits to be met in 1976. Emission limits previously adopted by California for 1975 remain the same. These California limits would require the use of catalytic mufflers on all 1975 models sold in California. California would in effect become a testing ground for catalytic mufflers.

There is considerable concern among auto manufacturers that even the new interim 1975 emission limits cannot be met without the use of catalytic or thermal reactors. While thermal reactors could be used to meet the interim standards, they are unlikely to be used since they would require replacement with a catalytic muffler to meet the 1976 standards.

Considerable debate continues concerning the necessity to install NO_x control on the majority of U.S. automobiles. Original NO_x data collected by EPA has been found to be invalid due to the measurement technique used. It now appears Los Angeles is the only city with a NO_x problem. EPA has testified that the statutory NO_x standard should be relaxed, but whether there will be a relaxation of the 1976 NO_x limitations is not yet known. Meeting the statutory NO_x limitations will result in a severe gasoline economy loss and thus additional volumes of crude oil will be required.

Over 40 percent of the 1971 automobiles were designed to have an octane requirement of more than 91 RON. The automobile industry has indicated that essentially all 1973 vehicles produced will operate on 91 RON gasoline. California legislation has been enacted which limits the octane requirement for any new car sold in California to 91 RON. The average compression ratio for vehicles has been reduced to provide satisfactory operation on gasolines of lower RON gasoline than those regular gasolines currently being marketed.

From the preceding discussion, it is clear that uncertainties exist, not only as to future quality required for motor fuels, but even actual volumes required as affected by exhaust system control devices. These uncertainties impose inhibiting influences on refinery expansion, as refiners wait for final definition in order to optimize new unit design.

Alternate Motor Fuels

Although essentially all vehicles in the United States are designed for either gasoline or diesel fuel, some limited use has been made of other fuels in spark-ignition engines. The three hydrocarbons that have received the most attention as alternates to gasoline are methane, propane and butane. The latter two, and mixtures thereof, are referred to as liquefied petroleum gas (LPG).

All of these paraffinic light hydrocarbons are excellent fuels for the spark-ignition engine from the standpoint of combining high-antiknock quality with clean burning characteristics, resulting in relatively low emissions of hydrocarbons and carbon monoxide. Their chief disadvantages are low boiling points, requiring pressurized fuel tankage on the vehicle--over 2,200 pounds per square inch (psi) for compressed natural gas (CNG) and over 200 psi for LPG, and the low-volumetric heat of combustion.

Light hydrocarbon fuels are being used for some vehicle fleets in large metropolitan areas. Because of logistic advantages in handling and storing LPG compared to liquefied or compressed natural gas, it is anticipated that LPG will receive greater acceptance in these vehicle uses than natural gas. Domestic availability will not permit extension of the use of such fuels for other than fleet operation.

Engine Trends (Spark-Ignited Piston Internal-Combustion Engines)

Conventional Engine: Technology for the control of gasoline engine emissions is now well advanced and is being developed to be applied to production engines to reduce emissions to low levels. Based on present developed technology, the conventional piston internal-combustion engine offers the best practical solution to a mass-produced, low-emission automobile for the next several years.

Stratified-Charge Engine: The stratified-charge engine offers the potential of low-emissions without after-treatment of the engine exhaust and with greater fuel economy than conventional engines with emission control systems to treat the engine exhaust. The basic stratified-charge concepts being developed were first suggested in the 1920's. The stratified-charge engine depends on ignition of rich fuel-air mixture which in turn ignites as larger volume of a fuel-lean mixture. By controlling the fuel-air mixing and the combustion in this manner and operating the engine at an overall fuel-lean condition, low emissions are produced. The statified-charge engine prototypes, that have been developed, indicate potential both in emission control and fuel economy. These engines represent modifications of the conventional piston engine and, therefore, should require somewhat less time to translate to mass production than other potential alternate engines.

Diesel Engines: The emissions from diesel engines, used almost exclusively on trucks, will be further reduced by controlling overloading and improving fuel injection and combustion. Smoke emissions, which are required to be controlled for the first time by the 1970 U.S. standards, may be further tightened. Odor problems are receiving increased attention. Diesel engines operating in congested areas may employ special control equipment to substantially remove remaining traces of pollutants from the exhaust.

Gas Turbines: The emissions from aircraft and stationary gas turbines will continue to be improved through improved injector and combustor design. Because of the favorable emissions characteristics of gas turbines, it is possible that greater use will be made of these engines in heavy-duty vehicles, off-highway equipment, and by 1980, possibly in automobiles. Also, greater use will be made of turbines for general aviation purposes. The trend toward use of turbines for stationary power plants continues to grow.

Rotary Engines: Increased use will be made of rotary engines, such as the Wankel, in small vehicles. The octane quality of fuel required for rotary engines will not be significantly lower than that required for current production of reciprocating engines. Rotary engines are now available on some imported cars, and it appears that they may become a factor in U.S. manufactured vehicles as early as the 1975 model year.

Electric Engines: Gasoline-electric, battery-electric and other types of hybrid electric-engined vehicles exhibit favorable emissions characteristics but suffer from range and acceleration performance limitations. These power plants will continue to be developed, but except for specialized uses, are not expected to be produced in significant quantities. Providing power for such vehicles would require additional electric power generating facilities.

Changes in vehicle engine design may not alter the type of fuel needed for those vehicles, at least up to 1980, but may increase fuel consumption and the demand for fossil-fuel resources substantially. However, the various designs again create uncertainty regarding the appropriate design basis for new refineries, since fuels required for each are obviously quite different.

Lead Time

Lead time for construction of new refineries or for modifications of existing refineries, even under normal circumstances, has always been long. For example, construction of a process facility (such as alkylation), based on known technology and with known past engineering as a guide, will nevertheless take 18 months to 2 years to complete from the time authority to proceed is issued. Obviously, the lead time required for new processes involving new technologies or complex additions to existing refineries may be much longer. It is not unusual for 5 or more years to elapse between the time a new process passes all research and pilot plant evaluation and commercial operations begin.

Environmental regulations contribute significantly to the lead time required to modify or build new refinery capacity. Time is needed to engineer and construct the special equipment necessary for the control of air and water effluent. But further time is also required to locate and obtain approval for a satisfactory site. More time is necessary to file impact statements to obtain construction permits and operating permits, and to comply with other details of the complex administrative procedures established by federal and state regulations and guidelines. These delays are minor problems, however, compared with the indeterminate delays which may result from court actions by concerned citizen groups.

Chapter Three

TRANSPORTATION AND STORAGE REQUIREMENTS

INTRODUCTION

The U.S. Energy Outlook Report of the National Petroleum Council projects that future oil demands will increase greatly from present requirements. In addition, it is possible that domestic production will not expand significantly above the current level, necessitating an increase in the importation of crude and/or products. The logistics system (including transportation and storage facilities), to handle increased crude as well as potential product imports will impact upon the consumer as well as upon the construction of U.S. refining capacity.

In order to determine a probable basis as to the location where imports will be required, and what type of facilities will be necessary, a projected interdistrict supply and demand balance for the United States is required. While such a balance takes into account existing fixed facilities (e.g., pipelines), it is not restricted to historical movement patterns.

During the 1970-1975 period, PAD Districts I, II, and, for a time, V will require substantial volumes of oil either from foreign sources or from other districts to meet projected demand. A portion of the increasing demand will be satisfied via overland imports (Canada), although the majority of increases of U.S. imports will come from the Eastern Hemisphere by water.

Today, the most advantageous way to transport crude by water is by movement directly from the crude source to consuming refineries in the largest vessels possible. Utilization of very large crude carriers (VLCC's), coupled with deepwater terminals, will provide the Nation with the most economic transportation system along with the environmental benefits which derive from reduced ship traffic.

Added importation of large quantities of oil will require substantial expansion of transportation and storage facilities, both to receive the oil and subsequently to transport it to the consuming locations. Considering only the lowest cost logistical system for importing crude oil to onshore refining centers, the amount of capital required for the increase in imports during the 1970-1985 period is very large. Estimated investments for the facilities, including new vessels, range from $14 to $16 billion (1970 dollars), depending upon whether PAD District I increases are directly delivered to PAD District I or -- as reflected in the higher number -- are supplied from PAD District III.

SUPPLY AND DEMAND BALANCES--1970-1985

Transportation and storage facilities necessary to handle the expanding petroleum demand are functions of the type of supply system, the supply source and the quantities and types of stocks to be transported. Three broad categories of supply in the United States can be considered: intradistrict supply, interdistrict supply and imports.

The large number of variables make accurate long-range projections of optimum supply systems a formidable task. In this study, primary consideration has been devoted to the development of systems which are capable of supplying increased demand levels within the basic supply system. Investments and/or systems for maintenance or efficiency improvements have not been addressed, but are factors that must be taken into account in an overall system analysis.

Tables 17 and 18 from the NPC's U.S. Energy Outlook Report outline the projected U.S. supply/demand balance for Cases II and III.* The four cases presented in this report assume different rates of finding oil, with changes in the success of oil discovery affecting the amount of natural gas available. The availability of a larger amount of gas in the "high oil finding cases" causes the demand for oil to be reduced as gas production satisfies a larger share of the total energy demand.

For this study, Cases II and III have been elaborated into a projection of a potential district-by-district balances and are shown in Tables 19 and 20. As accurate calculation of district balances is understandably difficult, it should be emphasized that the balances shown in Tables 19 and 20 are for illustrative purposes only. The indigenous supply and demand for each district has been developed from the same source as Tables 17 and 18. The interdistrict movements have been assumed to go from surplus districts to adjacent deficit districts. Imports which are shown are directed to the district of *ultimate consumption*, rather than the district wherein oil may be imported. In the base case, import increases above 1970 levels have been assumed to be crude rather than the variety of products which may be imported; however, discussion of product imports is included in the latter sections.

The assumptions of interdistrict movement are relatively simple and do not attempt to analyze specific projects regarding refinery construction of specific additions to the logistical system. Until substantial North Slope production is available, PAD Districts I, II, and V cannot meet demand requirements from indigenous supplies. After North Slope supplies become available, Districts I and II will continue in a deficit postion.

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* Cases II and III are both based on medium oil drilling rates. Case II provides for a high finding rate, Case III includes a low finding rate. Case III corresponds approximately with the NPC Initial Appraisal. The quantity of imports varies significantly between cases but total demand varies to a lesser extent. Thus, the variability in transportation and storage facilities is shown by contrasting Case II and III.

TABLE 17

U.S. PETROLEUM SUPPLY/DEMAND BALANCE—CASE II
(MB/D)

	1970	1975	1980	1985
Requirements*	14,716	17,551	20,513	23,068
Petroleum Liquid Production†	11,297	10,186	12,939	13,887
Synthetic Oil Production	–	–	100	480
Total Domestic Petroleum Supply	**11,297**	**10,186**	**13,039**	**14,367**
Petroleum Imports	3,419	7,365	7,474	8,701
Percent of Total Required Supply	23.2	42.0	36.4	37.7
Source of Imports				
Canadian Overland	766	1,275	1,925	2,750
Foreign Waterborne	2,653	6,090	5,549	5,951

* Oil required to balance total energy demand, net of processing gain, stock change, unaccounted for crude and other hydrocarbon inputs.

† North Slope production included in total production: 0 0 2,000 2,000

TABLE 18

U.S. PETROLEUM SUPPLY/DEMAND BALANCE—CASE III
(MB/D)

	1970	1975	1980	1985
Requirements*	14,716	18,251	22,335	25,787
Petroleum Liquid Production†	11,297	9,747	11,611	11,833
Synthetic Oil Production	–	–	100	480
Total Domestic Petroleum Supply	**11,297**	**9,747**	**11,711**	**12,313**
Petroleum Imports	3,419	8,504	10,624	13,474
Percent of Total Required Supply	23.2	46.6	47.6	52.2
Source of Imports				
Canadian Overland	766	1,275	1,925	2,750
Foreign Waterborne	2,653	7,229	8,699	10,724

* Oil required to balance total energy demand, net of processing gain, stock change, unaccounted for crude and other hydrocarbon inputs.

† North Slope Production Included in total productions 0 0 2,000 2,000

TABLE 19

SUPPLY AND DEMAND BALANCES
CASE II—HIGH OIL FINDING RATE
(MMB/CD)

PAD District	Supply and Demand Balances	1970	1975	1980	1985
I	Indigenous Supply	.1	—	.1	.2
	Demand	(6.0)	(7.2)	(8.3)	(9.0)
	Net	(5.9)	(7.2)	(8.2)	(8.8)
	Interdistrict Receipts from III Via Existing Pipelines	1.4	2.0	2.0	2.0
	III Other	2.0	—	—	0.1
	V	—	—	.8	.9
	Imports — Waterborne	2.5	5.2	5.4	5.8
II	Indigenous Supply	1.4	1.3	1.2	1.2
	Demand	(4.1)	(4.8)	(5.5)	(6.1)
	Net	(2.7)	(3.5)	(4.3)	(4.9)
	Interdistrict Receipts from III	2.0	2.1	1.7	1.3
	IV	.3	.2	.2	.6
	V	—	—	.2	.2
	Imports — Canadian	.4	1.1	1.9	2.8
	Waterborne	—	.1	.2	—
III	Indigenous Supply	7.8	6.9	7.0	7.3
	Demand	(2.4)	(2.8)	(3.3)	(3.9)
	Net	5.4	4.1	3.7	3.4
	Interdistrict Shipments to I Via Existing Pipelines	1.4	2.0	2.0	2.0
	I Other	2.0	—	—	.1
	II	2.0	2.1	1.7	1.3
IV	Indigenous Supply	.7	.7	.8	1.2
	Demand	(.4)	(.5)	(.6)	(.6)
	Net	.3	.2	.2	.6
	Interdistrict Shipments to II	.3	.2	.2	.6
V	Indigenous Supply	1.3	1.3	3.9	4.4
	Demand	(2.0)	(2.3)	(2.9)	(3.3)
	Net	(.7)	(1.0)	1.0	1.1
	Interdistrict Receipts	.2	—	—	—
	Shipments to I	—	—	.8	.9
	II	—	—	.2	.2
	Imports — Canadian	.2	.2	—	—
	Waterborne	.3	.8	—	—
	Total Imports	3.4	7.4	7.5	8.6

Note: For details of supply and demand assumptions, refer to NPC *U.S. Energy Outlook — A Report of the National Petroleum Council,* (December 1972) and to NPC *U.S. Energy Outlook — Oil and Gas Availability* (January 1974).
For 1975 on, assumptions include:
- All existing refining capacity is filled first.
- Base case assumes all district demands above 1970 levels are covered by increased refinery capacity within the district.
- All additional imports above 1970 level are assumed to be in the form of crude.
- PAD I Supply of refined products from PAD III assessed constant.
- PAD II Excess PAD IV production goes to PAD II.
  Excess PAD V production goes to PAD II via Transintermountain pipeline.
  Canadian imports go to PAD II after PAD V satisfied.
  Excess PAD III production after meeting PAD I refined products demand (2.0 MMB/D) provides balance of PAD II requirements.

TABLE 20

SUPPLY AND DEMAND BALANCES
CASE III—LOW OIL FINDING RATE
(MMB/CD)

PAD District	Supply and Demand Balances	1970	1975	1980	1985
I	Indigenous Supply	.1	.1	.1	.2
	Demand	(6.0)	(7.4)	(9.0)	(10.3)
	Net	(5.9)	(7.3)	(8.9)	(10.1)
	Interdistrict Receipts from III Via Existing Pipelines	1.4	2.0	2.0	1.9
	III Other	2.0	–	.3	–
	Imports	2.5	5.3	6.6	8.2
II	Indigenous Supply	1.4	1.2	1.1	1.0
	Demand	(4.1)	(5.0)	(6.0)	(6.8)
	Net	(2.7)	(3.8)	(4.9)	(5.8)
	Interdistrict Receipts from III	2.0	1.6	.7	–
	IV	.3	.2	–	.3
	V	–	–	.2	.2
	Imports – Canadian	.4	1.1	1.5	2.8
	Other	–	.9	2.5	2.5
III	Indigenous Supply	7.8	6.5	6.3	6.2
	Demand	(2.4)	(2.9)	(3.6)	(4.3)
	Net	5.4	3.6	2.7	1.9
	Interdistrict Shipments to I Via Existing Pipelines	1.4	2.0	2.0	1.9
	I Other	2.0	–	–	–
	II	2.0	1.6	.7	–
IV	Indigenous Supply	.7	.7	.6	1.0
	Demand	(.4)	(.5)	(.6)	(.7)
	Net	.3	.2	–	.3
	Interdistrict Shipments to II	.3	.2	–	.3
V	Indigenous Supply	1.3	1.3	3.6	3.9
	Demand	(2.0)	(2.4)	(3.1)	(3.7)
	Net	(.7)	(1.1)	.5	.2
	Interdistrict Receipts	.2	–	–	–
	Shipments to I	–	–	.3	–
	II	–	–	.2	.2
	Imports – Canadian	.2	.2	–	–
	Waterborne	.3	.9	–	–
	Total Imports	3.4	8.4	10.6	13.5

Note: For details of supply and demand assumptions, refer to NPC *U.S. Energy Outlook – A Report of the National Petroleum Council,* (December 1972) and to NPC *U.S. Energy Outlook – Oil and Gas Availability* (January 1974).
For 1975 on, assumptions include:
- All existing refining capacity is filled first.
- Base case assumes all district demands above 1970 levels are covered by increased refinery capacity within the district.
- All additional imports above 1970 level are assumed to be in the form of crude.
- PAD I Supply of refined products from PAD III assessed constant.
- PAD II Excess PAD IV production goes to PAD II.
  Excess PAD V production goes to PAD II via Transintermountain pipeline.
  Canadian imports go to PAD II after PAD V satisfied.
  Excess PAD III production after meeting PAD I refined products demand (2.0 MMB/D) provides balance of PAD II requirements.

The U.S. Energy Outlook Report's Cases II and III both project substantial increases in imported supplies during the period from 1970 to 1985. Case II imports increase from 3.4 MMB/CD to 8.7 MMB/CD during the period, while Case III imports reach a level of 13.5 MMB/CD by 1985. As outlined in the report, 1970 to 1975 will be the period of greatest relative and absolute growth. For Case III, the projected balances show that waterborne imports into District I will more than triple (from 2.5 MMB/CD to 8.2 MMB/CD during the 1970-1985 period).

Waterborne imports into District V will also triple (from 0.3 MMB/CD to 0.9 MMB/CD). District V imports are projected to continue to increase until North Slope crude arrives, optimistically estimated to start in 1976/1977. The Canadian imports which are shown have been derived from the U.S. Energy Outlook Report. Should future Canadian imports be restricted, it is likely the needed oil would come from the Persian Gulf via VLCC's and deepwater terminals to the Gulf Coast and subsequently move inland via pipeline.

Tables 19 and 20 have projected future oil demands by district with an individual district either receiving or shipping stock, not both. Table 21 outlines the historical transportation movements between the districts as a prelude to considering how each deficit district might be supplied. Movements of crude and petroleum products within the existing supply distribution system are primarily done via pipeline and marine facilities. Pipeline crude movements have historically been localized within PAD Districts (see Table 21) except for movements between Districts II and III and Canadian imports. Crude movements to District I from both Districts II and III have been primarily via barge or coastal tanker. Future demand increases will necessitate increasingly greater crude movements from foreign sources primarily to Districts I and III.

The large product movements into PAD District I have been made with a combination of marine and pipeline systems while movements into and within Districts II and III have utilized upriver barge and pipelines from Gulf Coast refining centers. Figures 8 and 9 illustrate the relative magnitude of petroleum movements as derived from Tables 19 and 20. Figures 10 and 11 show the increased transportation system capacity which would be required in the 1971-1985 period under Case II and Case III conditions, respectively.

METHODS TO MEET SUPPLY REQUIREMENTS

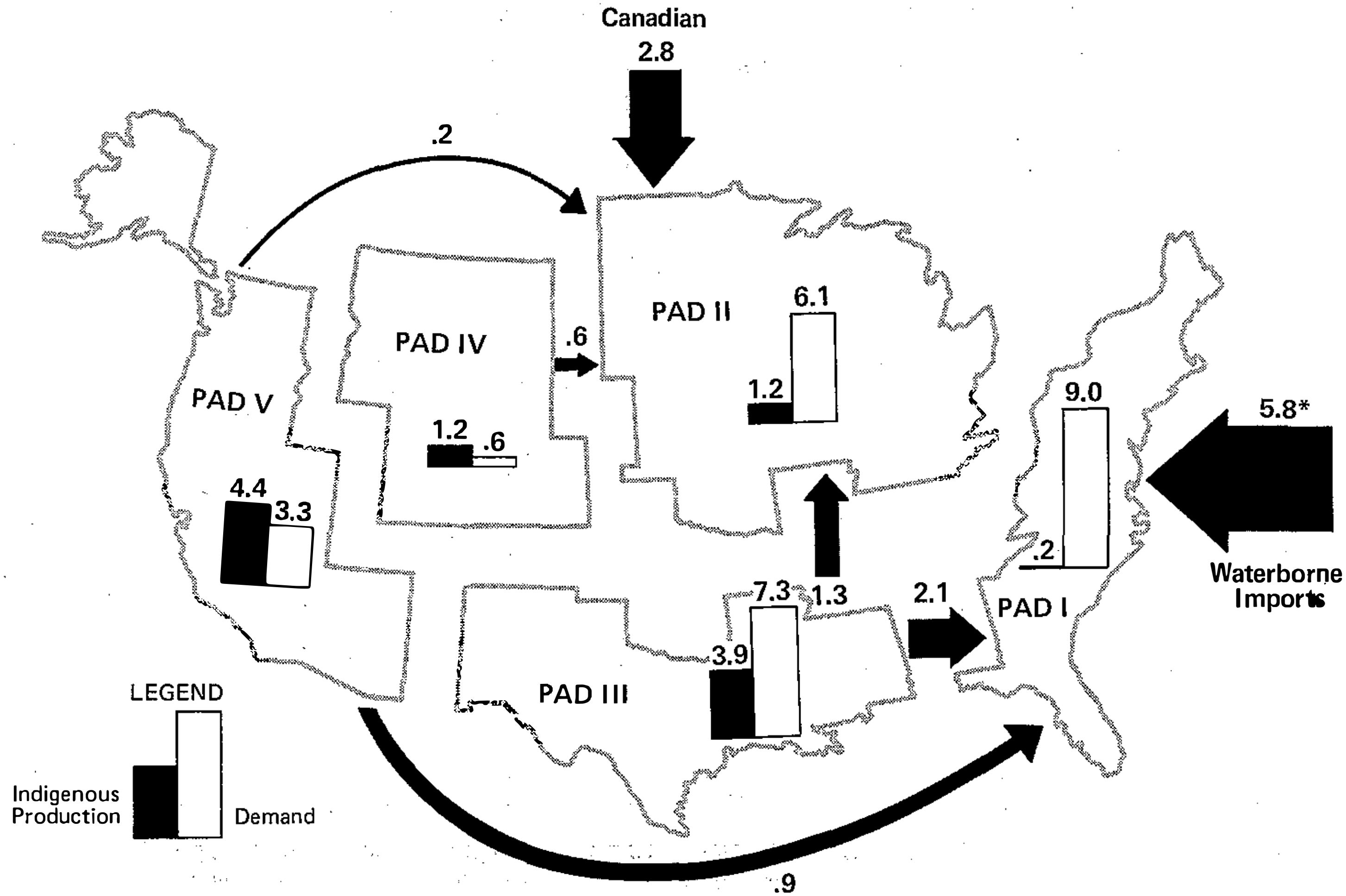
As noted earlier, future petroleum requirements will require large increases in imports during the coming years. In order to satisfy this growth of U.S. demand for petroleum products, substantial increases in transportation and distribution system capability will be needed. This section will deal with possibilities as to how the imports will move to the United States, what type of facilities are required and the cost of such facilities.

TABLE 21

SOURCES OF SUPPLY—1970
(MB/CD)

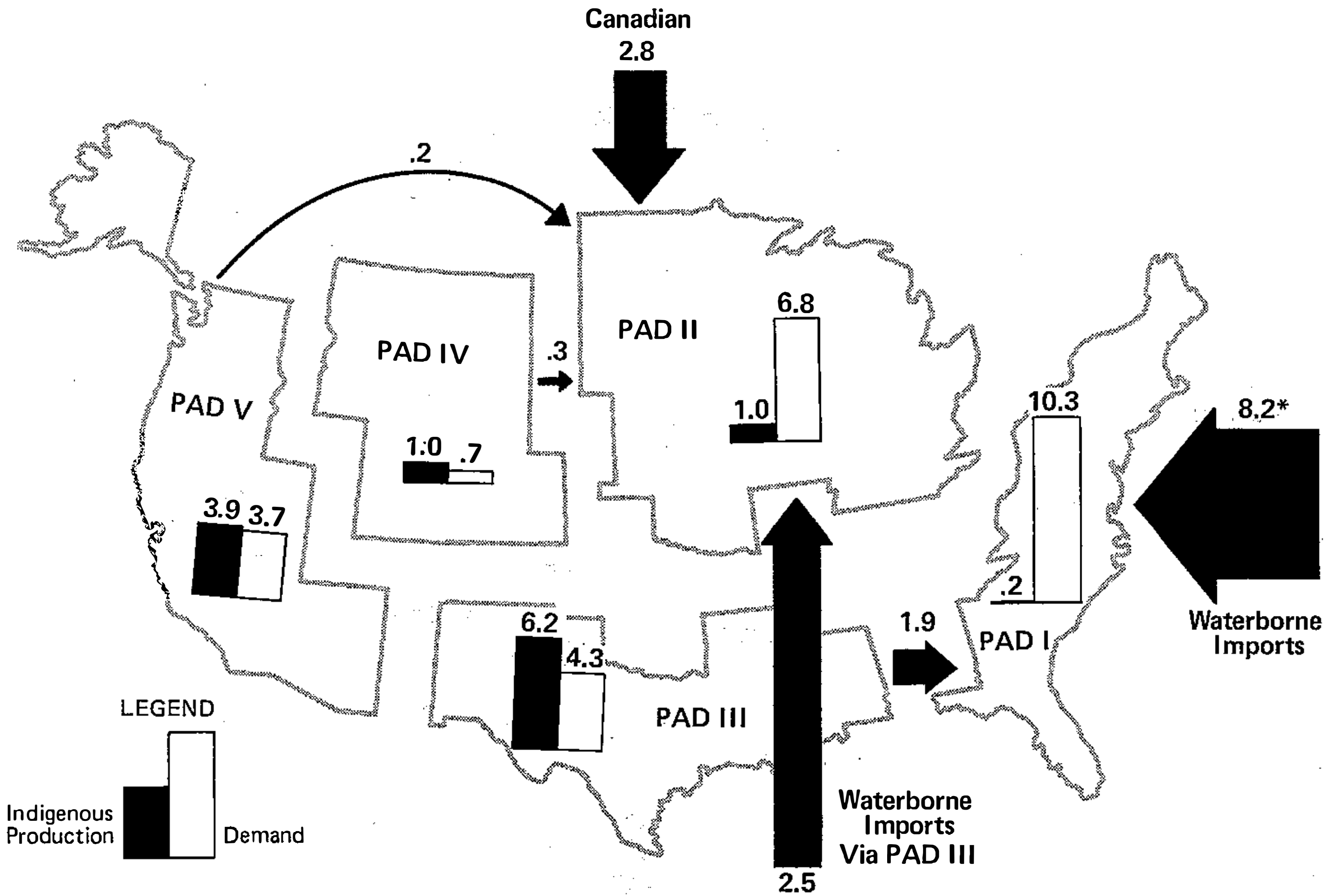
	PAD I		PAD II		PAD III		PAD IV		PAD V	
	Crude and Unfinished	Product	Crude and Unfinished	Product	Crude and Unfinished	Product	Crude and Unfinished	Product	Crude and Unfinished	Product
Domestic Production	31	—	1,169	—	6,507	—	675	—	1,254	—
Natural Gas Liquids	24	—	243	—	1,307	—	34	—	52	—
Receipts from Other Districts										
Marine:										
III to I	720	1,191	—	—	—	—	—	—	—	—
V to I	2	3	—	—	—	—	—	—	—	—
III to V	—	—	—	—	—	—	—	—	—	9
Great Lakes/Ohio River										
II to I	101	31	—	—	—	—	—	—	—	—
Mississippi Barge										
III to I	—	64	—	—	—	—	—	—	—	—
III to II	—	—	49	213	—	—	—	—	—	—
Pipeline										
I to II	—	—	—	120	—	—	—	—	—	—
II to I	12	56	—	—	—	—	—	—	—	—
II to III	—	—	—	—	3	72	—	—	—	—
III to I	5	1,442	—	—	—	—	—	—	—	—
III to II	—	—	1,406	322	—	—	—	—	—	—
III to IV	—	—	—	—	—	—	—	27	—	—
III to V	—	—	—	—	—	—	—	—	—	51
IV to I	10	—	—	—	—	—	—	—	8	—
IV to II	—	—	274	21	—	—	—	—	—	—
IV to III	—	—	—	—	8	—	—	—	30	—
IV to V	—	—	—	—	—	—	—	—	—	50
Imports	662	1,784	317	54	3	58	48	9	402	82
Total Supply	**1,567**	4,571	3,458	730	7,828	**130**	**757**	36	**1,746**	**192**

SOURCE: U.S. Department of the Interior, Bureau of Mines, *Mineral Industries Survey*, "Crude Petroleum, Petroleum Products and Natural-Gas-Liquids: 1970" (Final Summary) Washington, D.C., December 23, 1971.



* *PAD I Waterborne Imports could move into PAD III and then to PAD I (as products).*
Note: Volumes expressed in MMB/CD.

Figure 8. Petroleum Movements--Case II-1985.



* *PAD I Waterborne Imports could move into PAD III and then to PAD I (as products).*
Note: Volumes expressed in MMB/CD.

Figure 9. Petroleum Movements--Case III-1985.

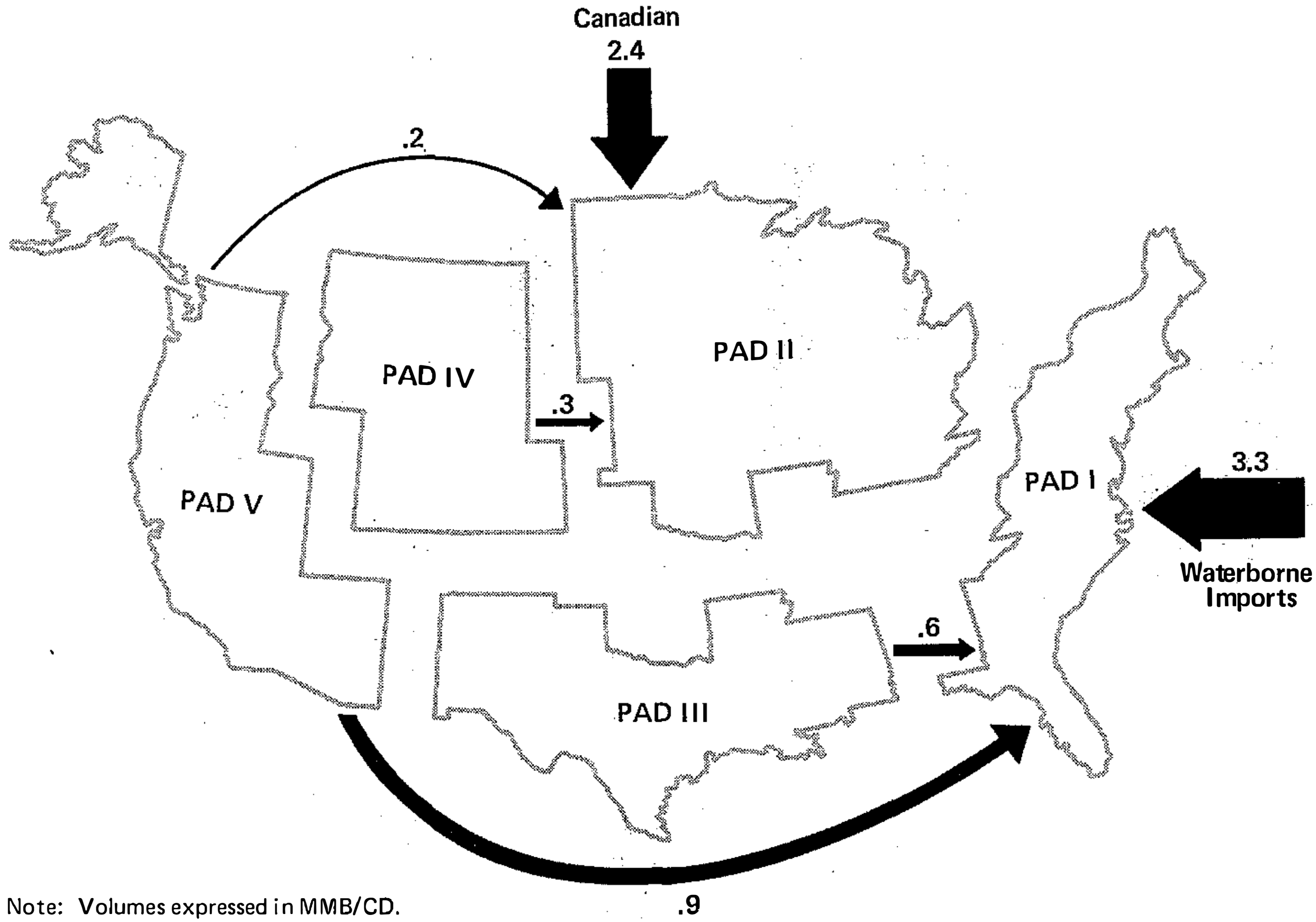
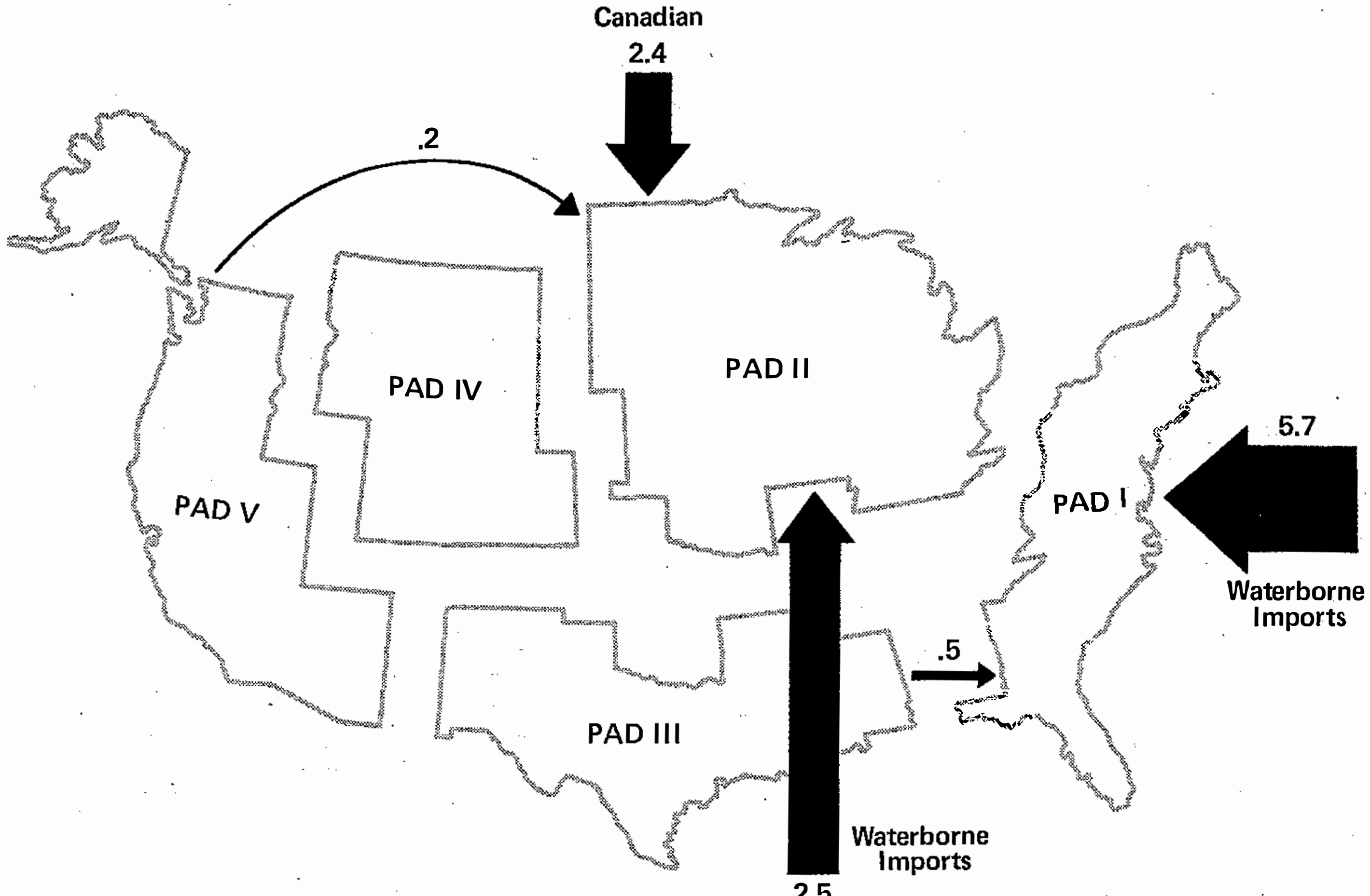


Figure 10. Increases in System Capacity--Case II-1970-1985.



Note: Volumes expressed in MMB/CD.

Figure 11. Increases in System Capacity--Case III-1970-1985.

MODES OF TRANSPORTATION AND STORAGE

Import of petroleum into the United States can be accomplished either with waterborne or with overland transportation systems. The inherent limitations in both supply and demand projections cause this study to deal only in general terms of requirements, to consider only the more desirable supply methods and to reference only major supply/distribution alternatives. Pipeline delivery has been well established as the most desirable mode for long distance overland movement. The most advantageous means of transporting required long distance waterborne crude imports today is by using VLCC type vessels in combination with deepwater terminals and pipelines connected to consuming refineries.

Marine Transportation

The primary categories of vessels which are of interest to this study and are used to transport petroleum include:

- Very large crude carriers (VLCC's)
- Transhipping vessels (crude oil)
- Product vessels
- Ocean-going barges/inland barges.

Crude Movements

Waterborne petroleum imports are projected to be some 6 to 11 MMB/CD by 1985 with most of the increase from current levels expected to come from the Persian Gulf.

For the long distance hauls from the Persian Gulf or Africa, the most economical and environmentally safe system to receive the oil is via direct shipment from supply source to the refining center in a combination of VLCC's and properly designed deepwater crude unloading terminals.*

VLCC is a general term applied to tankers of greater than 150,000 mean deadweight ton (150 MDWT) displacement. While specific sizes (such as 250 MDWT, 350 MDWT, 500 MDWT, etc.) are used in individual economic evaluations, the term VLCC does connote certain minimum requirements--primarily size (150 MDWT minimum) and required water depth (for 200 MDWT vessels about 65 feet draft plus clearance). However, the largest ships currently planned today may require 120 feet of water. The economics of size enable VLCC's to transport crude more economically on longer hauls than can smaller

* For extensive environmental and cost/benefit analysis of use of VLCC's for U.S. imports, see U.S. Department of Army, Corps of Engineers, *U.S. Deepwater Port Study*, Institute for Water Resources, Washington, D.C., August 1972.

vessels, providing port facilities are available to handle the VLCC's. In order to handle such vessels, ports must have berths of sufficient capacity and length and adequate tankage for unloading full cargoes. For shorter distances (movement within the Western Hemisphere), smaller vessels may provide a more economical total transport system when additional major terminal investments (dredging, berth and tank construction) are considered for handling the VLCC's large cargoes.

In crude transshipping, larger vessels are utilized for the initial, longer portion of the transportation movement, with the second stage shorter haul being moved directly to the consuming terminal or refinery in vessels sized to meet the terminal receiving capability. Illustrative of this type of transportation system are the existing and proposed terminals in eastern Canada and the Caribbean. These terminals can receive crude in VLCC vessels and then transship this crude to East and Gulf Coasts demand centers in smaller vessels (roughly a range of 40 to 70 MDWT for fully loaded vessels). In many cases, transshipping can provide substantial savings over direct movement in small vessels, however, it does not reduce the number of vessels calling at the final delivery point. Substantial reduction in vessel traffic is provided by direct movements to area deepwater terminals and final delivery by pipeline.

A further alternative for importation of crude is via direct movement from the crude source to the refinery in vessels of size similar to transshipping vessels (i.e., roughly 40 to 70 MDWT or larger if lightered). While this method eliminates the terminalling step involved in the transshipping case, the distances involved from the Persian Gulf make transshipping a more desirable alternative for economical petroleum supply to the Nation.

Product Movements

Product marine movements are generally direct from refineries to distribution terminals or large consumers. Included in this category would be U.S. Gulf to East Coast product movement as well as product imports. Use of VLCC's is not attractive for this type move because of the widespread demand and the number of terminals involved. Maximum loaded vessel sizing (roughly 50 to 75 MDWT in the United States) is controlled by port water depth; however, few existing terminals have sufficient dock capacity or tankage availability to receive full 75 MDWT product vessels.

Should increased petroleum demands be met by refining capacity constructed at offshore locations, then product imports would necessarily increase. Indeed, in the near term, the lack of construction of new onshore refining capacity will require that growing demands be met by major increases in product imports, which will continue to grow unless domestic refining capacity is added.

By 1985, PAD District I import levels will have increased to between 5.8 and 8.2 MMB/CD. Without addition of domestic refining capacity, the increased product demand will likely be met through waterborne imports from offshore refineries. In this case, product import levels to PAD District I alone would be in the 4.3 to 6.7 MMB/CD range, two to three times that of 1970. Assuming these imports were to move in average 40 MDWT vessels (which is larger than the current average dock capacity of the majority of East Coast terminals), product imports alone into District I could account for between 5,000 and 8,000 ship calls per year.

Product movement via barging or a tanker/barge transshipment mode is an alternative to direct tanker movements. Since barges normally do not carry volumes as large as those which can be handled on tankers, shore tankage requirements are generally less. New designs have allowed improved barge handling by more rigid tug/barge connections utilizing "notched" barges. Small barges draw less water than comparable tankers and hence can service shallow water terminals. Also, manning requirements are generally less on a barge operation than on conventional tankers of comparable size; however, barge speeds are normally lower than those of tankers.

Barging for short to intermediate moves, as well as longer moves up the Mississippi River from Gulf refining centers, has gained in popularity where the waterways permit realization of economic advantages associated with larger barges (200 to 250 MB per vessel) and the reduced operating costs. On longer movements (Gulf to East Coast), the economics of size tend to favor utilization of the larger tankers.

Environmental Considerations

One important objective in handling increasing volumes of imports is to minimize any adverse impact on the environment. Use of VLCC's make it possible to reduce the total number of ships required to import petroleum which thereby reduces the chance of collisions. Furthermore, since VLCC's require 70 to 100 foot water depths (which is more than existing terminals on the East and Gulf Coasts have), new deepwater unloading sites can minimize the intrusion of tankers into existing inner harbors, thus reducing the risk of groundings. Use of these terminals will not only permit a reduction in total number of vessels required to import crude but would also minimize the number of smaller tankers using existing ports and harbors. This combined effect will substantially reduce marine traffic congestion. Historical data on collisions and groundings indicate that most oil spilling accidents occur where harbor congestion is great and when the maneuvering of the ships is restricted by narrow winding channels.*

If the size of the ship carrying imported crude oil is held constant, then there must be a great increase in traffic to handle

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* Porricelli, Joseph D., Keith, Virgil F., and Storch, Richard L., "Tankers and Ecology." Paper presented at the Annual Meeting of the Society of Naval Architects and Marine Engineers, New York, November 11-12, 1971.

the increased volumes projected. In 1970, there were approximately 4,000 ship unloadings to handle petroleum imports to the United States. These ships averaged 30 MDWT. If projected 1985 imports (Case III) use this same average ship size, then traffic would increase to approximately 18,000 annual ship calls. If the ships averaged 75 MDWT (the largest loaded size currently handled on the East Coast), 7,500 calls would be needed. Port congestion from these ships would substantially increase the opportunity for accidents and perhaps increased water pollution. If, on the other hand, the imports arrived in ships of optimal size (including VLCC's averaging 250 MDWT), total activity could be reduced below the 1970 level to about 3,000 annual ship calls.

As indicated, product imports into PAD District I alone could account for some 5,000 to 8,000 annual ship calls moving on tankers if increased product demands were met through imports from offshore refineries. These movements would most probably be made directly to the demand terminals, normally located within the inner harbors, and would add to ship congestion in the inner harbor areas where maneuvering is most restricted.

The criteria of terminal efficiency includes, in addition to speed and economics, the assurance of environmentally safe operations. With the equipment possible under the existing technology, near pollution-free operation is attainable. For example, a current government report indicates that the Milford Haven port is operating with a loss of less than .0004 percent of the oil handled.* The Milford Haven terminal has no exotic pollution control equipment. Good design and adherence to good operating procedures have resulted in this type of operating record.

Economics

Historically, much of the crude oil run in East Coast refineries has come from the Gulf Coast region. However, as the Gulf Coast goes from a crude surplus to a crude deficit, the availability of domestic crude for the East Coast refineries will be eliminated. In 1970, about 55 percent of East Coast refinery runs utilized domestic crude. However, for the first half of 1972, only 29 percent was domestic, while almost 45 percent was imported from the Eastern Hemisphere. Soon the majority of crude going to the East Coast will come from the Eastern Hemisphere (primarily Persian Gulf). Other advantages aside, utilizing VLCC's on long hauls will provide the consumer the most economical supply of petroleum products.

Economics of waterborne movements favor use of the largest ship possible.† Figure 12 shows the relationship of vessel size

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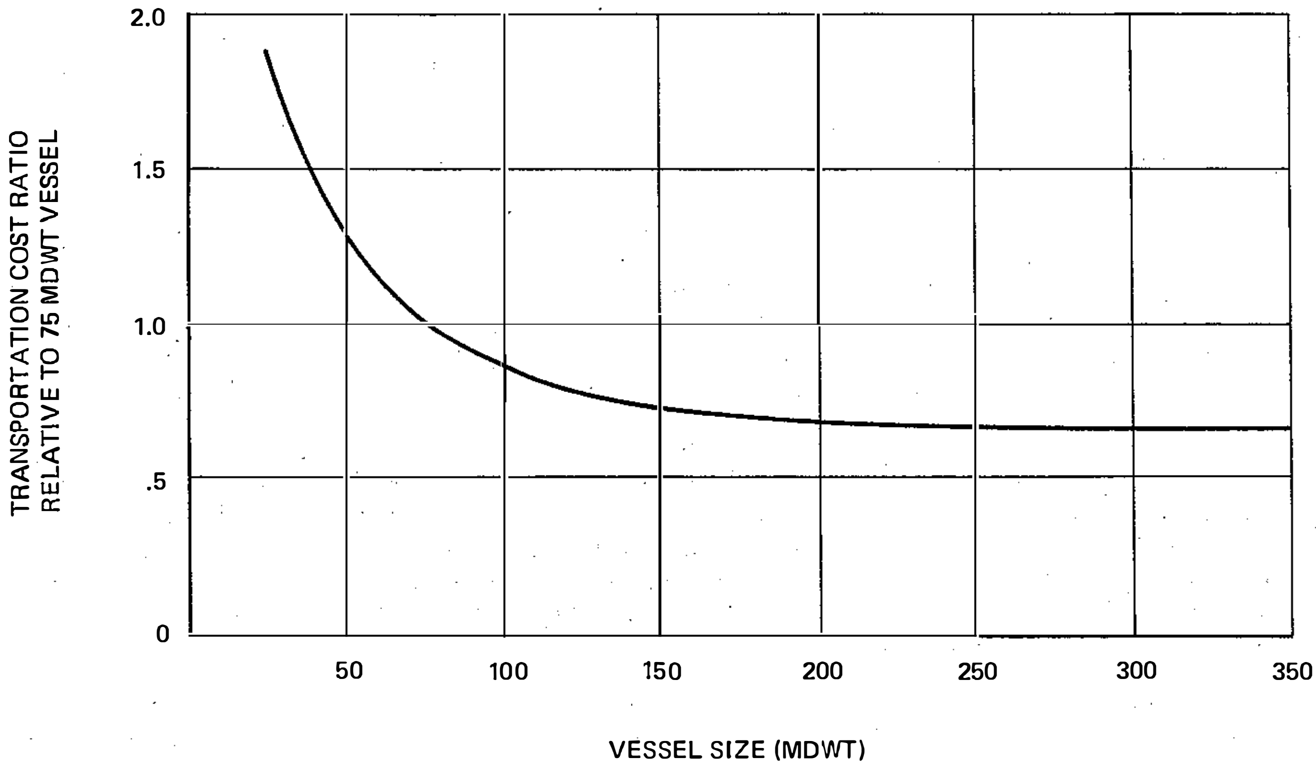
* U.S. Department of Commerce, Maritime Administration, Feasibility of a North Atlantic Deep Water Oil Terminal," Executive Paper, 1972.

† For general discussion of relative costs, see Cooke, Robert, "Modern Concepts of Ocean Transportation of Petroleum," American Society of Mechanical Engineers, August 1968.



SOURCE: Corps of Engineers U.S. Deepwater Port Study *IWR 72-8, 1972.*

Figure 12. Relative Transportation Costs for 10,000 Mile One—Way Voyages.

to relative cost for a 10,000 mile voyage, which is slightly less than a typical Persian Gulf to North Atlantic voyage. This figure shows the cost of transportation via a 250 MDWT vessel is about two-thirds that of a 75 MDWT vessel.

In the case of long distance crude movements, construction of offshore deepwater terminals permits the direct movement of crude using VLCC's to locations where it can be pipelined ashore. Transshipment provides economies over moving all crudes directly in small vessels (see Table 22). However, transshipping does not reduce the ultimate number of ship calls.

VLCC Deepwater Crude Unloading Terminals

As the earlier district supply balances indicated, there will be increased petroleum deficits in Districts I, II and V. Existing U.S. terminals are limited primarily by water depth from utilizing VLCC's in filling such demands.* Thus, deepwater terminal capacity

* Problems of deepening existing harbors include physical obstacles (relocation of bridges, tunnels, terminals, etc.) and rock; environmental problems (handling of dredging, dislocation of marine life); political competition for (against) facilities, and cost. The Corps of Engineers Report (*op. cit.*) and U.S. Department of Commerce, *The Economics of Deepwater Terminals*, Washington, D.C., 1972, go into these problems further.

TABLE 22

INCREMENTAL CRUDE OIL SHIP CALLS TO U.S. EAST COAST
FROM PERSIAN GULF—1970-1985
(MMB/CD)

Vessels Employed	Approximate Difference Over Base ($/Bbl)	Ship Calls Per Year*	
		Case II	Case III
VLCC Direct (250 MDWT)	Base	650	1,100
VLCC with Caribbean Transshipping Terminal (40 MDWT Transshipping Vessel)	0.25	4,000	6,800
75 MDWT Direct (Excluding Lightering Vessel Calls)	0.40	2,150	3,650

* Based on increase in imports over 1970: Case II, 3.3 MMB/CD; Case III, 5.7 MMB/CD.

is needed to serve the Nation's major concentrations of refining -- the New York-Philadelphia areas on the East Coast, Capline Midwest, the upper Texas Gulf Coast and the West Coast. Table 23 outlines existing port restrictions.

Unloading facilities for VLCC's, built as close as practical to the coastal refining centers, result in the lowest cost system of operation. This would ideally place the unloading facility just offshore, with onshore distribution made by pipeline.* The site

TABLE 23

EXISTING PORT RESTRICTIONS (DRAFT AND DEADWEIGHT)

U.S. Refining Area	Draft (Feet)*	Estimated Fully Loaded Vessel Size (MDWT)†	Estimated Light Loaded Vessel Size (MDWT)‡
N.Y. Harbor (Stapleton Anchorage)	45	80	—
(Arthur Kill, South End)	36	35-40	100-120
Philadelphia	38.5	45-50	100-125
Louisiana (Capline)	39-40	50	100
Houston	39-40	50	100
Los Angeles/Long Beach	35/51-52	30-35/100	80/120
San Francisco (Richmond)	36	30-35	100-125
Seattle (Cherry Point)	60	130	130

* These values represent going maximum draft limitations at terminals. Capline (at St. James) is fresh water.

† Vessel dimensions vary considerably. The sizes shown are considered representative; however, in most every case there are larger vessels of equivalent draft. Such special design vessels may have sacrificed other characteristics such as investment or operating speed to achieve such dimensions.

‡ Vessels lightered to draft available. Channel and berth limit size of ship. For detailed discussion of lightering, see Corps of Engineers report, *U.S. Deepwater Port Study*, IWR 72-8 (1972).

* For illustrative calculations comparing deepwater offshore oil terminals with and without pipeline service, see Soros Associates, Inc., *Offshore Terminal System Concepts*, 1972.

must have sufficient deep water, adequate shelter from storms, uncongested approaches from the sea and minimum potential for environmental disruption.

In addition, if it is not at an existing terminal or refinery, the site should have an onshore area suitable for oil storage facilities and access to a sufficient infrastructure for support of the facility. Specific site locations for deepwater terminals are currently under study by governmental and industry groups. Much work has been done by the Corps of Engineers (previously cited), which is responsible for development of harbors. The Council on Environmental Quality is making extensive studies of seven locations.* The Maritime Administration has commissioned the Soros study (previously cited) of a multipurpose terminal off the Delaware Coast. Jointly owned terminals have been studied in the lower Delaware Bay area, off Louisiana and the Texas Gulf Coast; individual projects have been discussed for many additional sites.† However, there have been specific rejections or legislative prohibitions of several VLCC terminal proposals on the East Coast. (Sites included are Machiasport and Searsport, Maine and Delaware Bay, Delaware.)

Two or possibly more terminals may be required in areas where total crude requirements of individual refiners exceed the economic throughput of a single terminal. Construction of more than one terminal will also alleviate marine traffic congestion which would otherwise occur in the vicinity of a single terminal.

VLCC Terminal Design

The studies mentioned previously (Corps of Engineers, Soros, etc.) present detailed information on VLCC terminal design. Let it suffice here only to outline the general criteria and types of design generally considered.

The ideal offshore unloading facility should allow maximum berth occupancy under prevailing weather conditions, fast total turnaround time and a reasonable investment and operating cost. It should be safe, environmentally sound and consistent with proven technology.

Multiple-use offshore deepwater port concepts (i.e., crude, coal, ore, etc.) compromise the safety, efficiency and economics of single-use crude facilities. Specialized equipment and technology have been developed for use in terminals which handle crude unloading only. Multiple-use ports are undesirable because they

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* See U.S. Congress, Senate Committee on Interior and Insular Affairs, *Deep Water Port Policy Issues*, Serial No. 92-96, April 25, 1972.

† *The President, in his energy message to Congress of April 18, 1973, proposed legislation for Congressional consideration granting the Department of Interior authority to license deepwater terminals in federal waters.*

involve more complex designs and operating procedures and attract increased vessel traffic. Consequently, such ports result in higher investment and operating costs and unnecessary increases in maritime and terminal operating risks.

Types of facilities used for VLCC crude terminal application include: sea islands, fixed piers, multipoint mooring systems and single-point mooring systems (monobuoys or SPM). There are variations of each type in use, and each has its advantages and disadvantages, depending upon location and design criteria.

Where sheltered deepwater sites occur naturally, a conventional fixed pier type terminal may be suitable. However, in unprotected areas where weather can be troublesome, the fixed berth system would be both expensive and have a lower berth utilization factor than a monobuoy. With a conventional pier type terminal, the moored vessel has a fixed direction and under adverse weather conditions can impose heavy stresses on the terminal facility. This factor also applies to the multipoint mooring system because utilization is limited by the direction of the prevailing seas relative to the heading of the system. Conversely, the monobuoy design allows the tanker to swing around the buoy with wind and current changes providing a higher utilization factor. It also provides more safety in the unloading operation in open sea conditions. The fixed berth design is generally limited to about 3 foot waves which are often exceeded in open seas. Monobuoy designs, on the other hand, can safely conduct unloading operations in up to 10 to 15 foot seas.

Cargo Preference Legislation

Cargo preference bills such as those which have recently been before Congress would, if enacted, directly and negatively affect the economic feasibility of U.S. refining. While the most recent bill before the Senate was defeated, there will undoubtedly be continuing attempts to impose U.S. flag vessel preferences for the shipment of imported oil.

The justification for cargo preference legislation, which would require a certain percentage of oil imports to be carried in U.S. flag vessels, is the creation of incentives to build up and maintain a healthy and viable U.S. flag fleet. Although such legislation is intended to improve and benefit distressed conditions in the American Merchant Marine fleet, it raises far more serious problems and complications with regard to: (1) U.S. relationships in international trade, (2) the economics of the domestic refining industry and (3) future cost of energy to American consumers.

There are a great number of substantive reasons why the cargo preference bills are contrary to national economic interests, national security objectives, consumer objectives and specifically, to the oil refining industry.

- The cargo preference legislation would invariably raise costs to the refiner which can be expected to lead to higher retail prices. Thus, there is a direct and negative impact on consumer interests. Moreover, the cost will continue to rise as the United States becomes more dependent upon oil imports.

Within the framework of the National Petroleum Council's Energy Outlook Report, it is evident that crude oil imports could increase significantly through 1985, with most of the additional crude imports originating from longer haul sources in the Eastern Hemisphere. Thus, the "consumer" cost of cargo preference would be increasing substantially each year.

- In the broader sense, one of the more difficult aspects of cargo preference legislation is that it would be contrary to the principles of international trade to which the United States has long subscribed. It would contravene the intent and objectives of international agreements between the United States and other countries, a considerable number of which were sponsored by this country. Specifically, it would be a departure from the long-established principle of freedom of choice of carrier for private goods being imported into this country. Moreover, cargo preference legislation could lead to a proliferation of special bilateral shipping arrangements which would be contrary to the U.S. policy of multilateral trade.

  There can be little doubt that such a fundamentally restrictive move on the part of the U.S. Government would spur oil producing countries to retaliate. By imposing cargo preference legislation of their own, they could require that a certain portion of any oil exported must henceforth be carried in their national vessels. The negative effects on the domestic refining industry of such polarized shipping patterns would be serious today and would become more serious as the U.S. imports increase by larger volumes of crude from abroad.

- Narrowing these "flag questions" to the oil industry, and specifically to the refining industry, this study reflects a need for about 9 MMB/CD of additional refining capacity in the United States by 1985. Cargo preference legislation would have a serious adverse effect on new refinery construction to meet this growing demand for products. Such legislation would force refineries to import a portion of their crude in U.S. flag vessels. This would mean that, as foreign crude accounts for a larger and larger share of total refinery crude inputs, the landed cost of the average barrel of crude would be higher. To the extent that refineries would have to draw crude increasingly from the Middle East, the long haul would raise costs substantially.

  Cargo preference legislation would also severely affect the economics of any incentive plan designed to locate new heavy fuel oriented refineries in the United States. These plants would run primarily, if not exclusively, on foreign crude. Such new U.S. plants would, however, be competing with existing heavy fuel oriented refineries located offshore. If these U.S. refineries must use U.S. flag vessels to import a large portion of their crude, they may well not be competitive with existing foreign heavy fuel refineries. Under such circumstances, it is most likely that refiners would continue to see an incentive to locate heavy fuel refineries in the Caribbean and other adjacent areas.

- Any increase in foreign petroleum import costs would also adversely affect the competitiveness of U.S. petrochemical manufacturers who rely upon imported crude for a portion of their feedstocks.

Cargo preference legislation could have adverse effects on all existing U.S. refiners. The cost of U.S. tonnage in place of foreign tonnage would add to the already high price of foreign crude. Thus, refiners will become more reluctant to absorb the costs of foreign crude rather than rely on domestic crude. The result will aggravate the shortage of domestic crude and may cause refineries to spare their capacity. In turn, this would aggravate the growing shortage of petroleum products.

If indeed there is a case for a strong U.S. flag fleet from the standpoint of national security, then the subsidies required to build and operate such a fleet should be covered by the Merchant Marine Act. In fact, a comprehensive Merchant Marine Act providing construction and operating subsidies is already in effect. Under this Act U.S. Government grants, financed loans and direct federal operating differential subsidies are offered. However, this Act is based on dry cargo and liner transportation concepts which are not readily applicable to tanker and dry bulk trading. Consideration should be given to modifying and liberalizing the Merchant Marine Act to apply to the special needs generated by the bulk segment of the U.S. maritime industry.

Pipeline Transportation

In addition to marine transportation, pipelines are a major mode of transportation for petroleum. In 1971, some 64 percent of movements between PAD Districts were made by pipeline. Generally, pipeline transportation cost is lower than other means of transport except possibly direct water transportation of significant size. However, pipeline costs include a high capital investment in fixed facilities. Hence, substantial movement of material assured over a long period of time is required to economically justify pipeline construction.

The increasing dependence on foreign oil will necessitate additional pipeline systems designed both to move crude from offshore unloading terminals and to transport adequate supplies to the many refineries in the country which do not have direct marine access. Additionally, should major expansions of refining capacity occur on the Gulf Coast, it is logical to assume that there will be increasing numbers of product pipelines for moving products from the Gulf Coast to both the Midwest and the East Coast. The need for pipeline capacity to the inland refiner is underlined by the survey results which indicate that the 1978 PAD District II crude running capacity is not matched by crude receipts, with a deficit of 0.4 MMB/CD.

Environmental Considerations

Routes for crude pipelines have been established from existing domestic producing areas to refining areas. Major product pipelines run from PAD District III to Districts I and II, as well as within PAD Districts. However, new pipeline routes may become more difficult to create because of environmental restrictions. The North Slope Alaskan pipeline is a recent example of the difficulties involved. Much pipeline capacity may be added to existing systems by addition of parallel, joined lines ("looping" systems),

TABLE 24

INTERDISTRICT PIPELINES

	Crude			Products		
To	From	Major Lines	Diameter (Inches)*	From	Major Lines	Diameter (Inches)*
PAD I	Canada	Interprovincial	12	III	Colonial	36
	II	†	—		Plantation	12, 18, 20
				II	†	—
PAD II	PAD III	Capline	40	I	†	—
		Mobil	20	III	Texas Eastern	20
	IV	Amoco	22		Explorer	28
		Platte	20			—
		Arapahoe	18	IV	†	—
	Canada	Lakehead	18, 24, 34			
PAD III	IV	Texas/New Mexico	16	II	†	—
PAD IV	Canada	†	—	III	†	—
PAD V	III, IV	†	—	III	†	—
	Canada	Trans Mountain	20	IV	Southern Pacific	18, 12

* Line size is only very rough measure of potential capacity. Pump stations, line pressure and stock handled also affect capacity.

† Indicates numerous smaller lines.

TABLE 25

COMPARATIVE SUPPLY CONSIDERATIONS

Importation Supply (Persian Gulf)	VLCC	VLCC/40 MDWT Transship	75 MDWT Direct
Cost	Lowest	Mid	Highest
Environmental Risk	Lowest	High	High
Security Risk	Equal	Equal	Equal
Flexibility	Lower	Higher	Higher
Inter-Intra District Supply	**Pipeline**		**Marine**
Initial Investment	High		High
Operating Cost	Low		Higher
Inflation Effect	Low		High
Environmental Risk	Low		Higher
Security Risk	Equal		Equal
Flexibility	Limited		High

as well as by increasing the number of pumping stations along pipeline routes. Current major interdistrict pipelines are outlined in Table 24 including source, destination and nominal diameter.

Table 25 summarizes comparative supply considerations for import and inter- and intradistrict transportation systems.

Rail and Truck Transportation

Rail and truck facilities are currently used primarily to transport specialties (lubes, asphalt and liquid petroleum gas (LPG) products) from refineries to terminals or customer locations, as well as motor gasoline to the retail outlets. Movements of crude by rail have been essentially eliminated, while crude movement by truck is primarily limited to a field gathering mechanism.

Rail and truck transportation is normally more expensive than pipeline or water movement and, therefore, is used only where alternative modes are not available. As a broad generalization, rail transportation becomes more economical than trucking on distances over 200 to 300 miles. In the longer range, it appears that specialties (lubes and asphalt) will continue to move by rail and truck to accommodate future growth levels. However, products such as LPG, which now comprise a portion of rail movements, will decrease in movement due to competitive advantages of pipeline and truck systems. The future rail movements should, therefore, comprise a decreasing portion of petroleum transportation.

Storage Facilities

Refinery storage may be divided by type of inventory (crude, intermediates, products) as well as by use (receipt or shipping, working or seasonal, available or unavailable). Storage capacities derived from the NPC questionnaire, with response covering 90 percent of U.S. refining capacity, are shown on Table 26.

Tankage volume is a function of demand and means of transportation. Working volume is generally sufficient to handle the maximum receipt rate with normal withdrawals. Hence, when a pipeline supplies a refinery at essentially refinery operating capacity, little crude tankage may be required except for protection and flexibility. However, when crude is delivered by ship, tankage volume is equal to the ship size plus allowance for variation in shipping schedule. The same principles apply to product shipment -- i.e., rate and means of shipment affect volume. In addition, the volume of product tankage is influenced by seasonal demands for products.

Future crude tankage volume requirements will be affected by the increased percentage of imported crude, movement of crude over greater distances, as well as the increase in average vessel size. At the same time, product tankage requirements will also increase due to increasing demand levels. The optimum amount of tankage at a refinery is a function of the size and frequency of crude arrivals and product shipments. The trade-offs are excess tankage on the one hand or tanker delay, commingled stocks or refinery downtime on the other. A common guide of experience in sizing marine crude receiving tankage is to provide a minimum of 10 days operation plus one (maximum) vessel-size tankage volume. Number, types and relative amounts of stocks also affect the absolute volume of tankage required.

TABLE 26

PETROLEUM STORAGE CAPACITIES

	Shell Capacity Days of Crude Run
Crude Tankage Capacity	
Available	22
Unavailable	9
Total	**31**
Intermediate/Product Tankage Capacity	
Available	65
Unavailable	23
Total	**88**

PAD DISTRICT REQUIREMENTS FOR TRANSPORTATION AND STORAGE FACILITIES

The preceding material has outlined the type of facilities required to handle the added volume of imports which will be required to satisfy increasing energy demands. These facilities include importing crude tankers, deepwater terminals and pipelines to interior district refineries. Table 27 outlines projected costs associated with handling the increased volumes of imports. Additionally, but not included within these estimates, substantial facilities will be necessary to handle intradistrict requirements -- the North Slope Alaskan pipeline, tankers for crude movement from Alaska to the West Coast and intradistrict pipelines. The magnitude of these facilities can only be roughly approximated; however, cost estimates at the $6 to $8 billion level appear reasonable.

The Base Case assumes that all increases of imports are in the form of crude oil delivered directly to the consuming district. Hence, increases in PAD District I imports go directly to District I; District II imports (after Canadian receipts) are moved from Gulf VLCC terminals via pipeline to District II. The total investment in tankers, terminals and lines was $7 to $14 billion.

As an alternative, a Memo Case considered supplying PAD District I demand by imports into the U.S. Gulf and subsequently transporting refined products to the East Coast. Both pipeline and tanker capacity was projected for the added 3.3 MMB/CD movement. The cost of the Memo Case was $9 to $16 billion.

These estimates project a lower limit to investments required, due to utilization of 1970 dollars, as well as to exclusion of the

TABLE 27

TRANSPORTATION AND STORAGE REQUIREMENTS*
FOR HANDLING INCREASES IN OIL IMPORTS—1971-1985
(Billions of Dollars—1970)

	Case II—High Oil Finding Rate				
	VLCC's	Domestic Ships	VLCC Terminals	Pipeline	Total
Base Case	4.6	1.2	.3	1.2	7.3
Memo Case: If PAD I Imports Are Refined in PAD III	4.6	2.3	.3	1.9	9.1
	Case III—Low Oil Finding Rate				
Base Case	11.4	—	.8	1.8	14.0
Memo Case: If PAD I Imports Are Refined in PAD III	11.4	1.2	.8	2.5	15.9

* Only terminal storage included; refinery storage included elsewhere in refinery investment. No working capital included.

many intradistrict additions which will be required. Additionally, the estimates do not include the likely substitution of Persian Gulf crude for declining Western Hemisphere production outside the United States. While not increasing the absolute amount of imports in itself, the substitution will encourage replacement of small vessel deliveries by VLCC's with attendant deepwater terminal capability.

CURRENT SITUATION AND FIRM PLANS: NPC SURVEY RESULTS

The previous parts of this secton on transportation have outlined the volume of anticipated PAD District deficits. This part reviews U.S. refiners' existing facilities, firm plans and potential expansions which are presently under consideration by domestic refiners as indicated in the NPC questionnaire.

Crude Deliveries

Refiners reported plans for increased receipts of crude via water transportation. As seen in Table 28, PAD District III and V show the largest increases.

However, these numbers may understate the magnitude of the problem because, as indicated in prior sections, reported U.S. refinery capacity increases will not meet demand levels. The reported PAD District I waterborne crude receipts will increase from 23 percent domestic, 62 percent foreign input level in 1972 to 16 percent domestic, 71 percent foreign by 1978.

Refiners have generally projected crude receipt increases to be equal to crude capacity increases. However, in PAD District II, about 0.4 MMB/CD of crude running capacity (by 1978) has not been matched with anticipated crude receipts. As the supply balances made earlier indicate, substantial pipeline capacity -- both from Canada and the Gulf -- is yet to be defined for PAD District II.

Marine Movements

There is a great disparity between what refiners plan to do about marine facilities and what would have to be done to maximize

TABLE 28

REFINERY RECEIPTS OF CRUDE OIL DIRECTLY BY WATER
(Percent of Total Crude Oil Received)

	PAD Districts			
	I	III	V	Total U.S.
1972	85	15	45	27
1978	87	30	59	38

use of existing sites. Only a net of four berth additions (1972 to 1978) were reported in the NPC questionnaire as planned, split between Districts I, III and V. Thus, the total reported berths go from 233 in 1972 to 237 in 1978. Most of these berths (138 in 1978) have a water depth of less than 35 feet. Only two locations exist with 60 feet or more of water, both in PAD District V. Results of the refinery survey reveal that, if existing refineries were to expand to make maximum use of the existing refining sites, over 60 marine facilities would need to be constructed or developed, and nine of these would require over 60 feet of water.

Tank Car and Tank Truck

As anticipated, rail and truck movement of crude is planned to decrease as a percent of overall crude capacity. Survey results indicate 1972 rail/truck receipts at 1.1 percent of capacity *versus* 0.9 percent in 1978. Product movements by rail/truck from refineries are projected to remain at about the same level (13 percent of capacity).

Tankage

The NPC refining survey included questions on shell capacity of crude as well as intermediate and product tankage capacity. The results are summarized in Table 29 in terms of days of crude run capacity. As the table shows, Districts II and V show significant changes in capacity; District II increases its reserve, while District V decreases its crude tankage volume. Similarly, intermediate and product tankage decreases with respect to crude running capacity most significantly in PAD District V.

Tankage volumes have historically tended to decline in terms of crude capacity. The increase in PAD District II's crude storage capacity may be in anticipation of more imported stock; however, response to delivery method (see Table 29) did not indicate this.

Refinery tankage, described in terms of days of crude running capacity, has historically tended to decrease over time. The results of the refinery survey show this trend continued relative to reported planned refining capacity. Reported 1972 crude intermediates and product storage capacity available was 87.5 days of crude run, declining to 82.1 days in 1978. This is about the same rate of decline as estimated for actual inventory (as opposed to capacity) from Bureau of Mines data.* This would indicate a trend towards higher utilization (i.e., inventory level divided by capacity) at the end of the period. Higher utilization is in line with historical trends.†

However, if the refining shortfall is to be met with onshore capacity, proportionate volumes of tankage must be added. Alter-

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* NPC, *Petroleum Storage Capacity*, 1970.

† *Ibid.*

TABLE 29

NPC 1972 REFINING SURVEY—CRUDE, INTERMEDIATE AND PRODUCT TANKAGE
(Days of Crude Running Capacity)

	Total U.S.	PAD District I	II	III	IV	V
1972 - Crude	30.7	17.5	62.4	13.4	20.6	38.3
Unavailable	(8.6)	(6.3)	(12.4)	(5.3)	(6.9)	(12.3)
Net	22.1	11.2	50.0	8.1	13.7	26.0
Intermediates and Products	88.1	83.9	113.4	78.2	76.8	77.6
Unavailable	(22.7)	(23.8)	(17.6)	(25.2)	(18.1)	(19.5)
Net	65.4	60.1	95.8	53.0	58.7	58.1
1978 - Crude	31.0	15.6	80.7	13.1	19.6	29.9
Unavailable	(7.8)	(5.6)	(12.4)	(5.0)	(6.5)	(10.1)
Net	23.2	10.0	68.3	8.1	13.1	19.8
Intermediates and Products	78.5	71.3	114.5	74.0	73.0	58.9
Unavailable	(19.6)	(19.9)	(17.8)	(22.4)	(17.2)	(15.0)
Net	58.9	51.4	96.7	51.6	55.8	43.9

natively, tankage will be required in the United States for increased product import volumes to meet the refining capacity shortfall. Much of increased product imports may be expected to go directly to consumers (such as shore-located power plants) or distribution terminals. For example, in PAD District I, the largest importing district, significant volumes of storage are located at terminals not associated with refineries. These storage capacities were not included in the refinery storage data of the 1972 NPC survey questionnaire. Hence, no statement can be made on the adequacy of tankage to receive imported products.

CONCLUSIONS

U.S. refiners will not expand or add new capacity to meet increasing demands for petroleum products unless adequate dependable supplies of crude are available. Due to the declining trend of U.S. production, the oil to meet increased demands will have to be imported. The increasing demand for foreign petroleum will necessitate substantial changes to existing transportation systems. For the longer haul, imports from the Persian Gulf and the use of VLCC's, combined with optimally placed deepwater terminals, can provide the Nation with both environmental and economic benefits. Movement of the required imports in less than an optimum transportation system will result in higher consumer costs and added environmental risks. Utilization of VLCC-type ships results in a lower number of vessel arrivals; and, moreover, use of the larger ships provides significantly lower cost per barrel moved.

If direct VLCC movements are not possible, then the next most viable alternative for handling the increased crude imports would be to utilize VLCC's combined with transshipping from offshore foreign terminals. However, vessel traffic would tend to grow proportionately with increasing levels of imports resulting in major congestion in existing harbors.

Assuming utilization of VLCC's to import foreign oil, a number of deepwater terminals will be required to handle the VLCC's. Today there are numerous proposals for VLCC terminals in the United States. Within PAD District I, VLCC terminal plans have not proceeded beyond conceptual planning stages to date due to governmental as well as environmental opposition to proposals. Proponents of terminals have not been successful in obtaining recognition that the VLCC's provide, both environmentally and economically, a better solution to problems of the immediate and long-run energy supply situation.

On the other hand, plans for VLCC terminals in District III are progressing, and two projects have reached design stages. District V's most pressing need for VLCC capacity will be in California; however, no current plans are in process.

In addition to the major marine transportation systems required to import foreign petroleum to the United States, the increasing demand levels will necessitate changes within the existing operating system. Additions to both pipeline, storage and terminal facilities will be required to handle future demands.

The location of added domestic refinery capacity will heavily influence the transportation and storage systems. Major capacity additions to Gulf Coast capacity will require system increases in transportation facilities to move products from the Gulf to both the Midwest and the East Coast.

Cost of the major components of the transportation systems required to handle only the additional imports and to transport this product from refineries to terminals will approach $9 to $16 billion.

Storage volume additions reported by refiners are generally in line with capacity added and historical trends. However, since planned refinery expansions are not projected to meet demand, additional storage capacity will be required. A portion of this capacity will be provided by terminals not associated with refineries and are not included in this survey.

Chapter Four

PETROLEUM REFINING AND PETROCHEMICAL PLANT ECONOMICS

INTRODUCTION

Important changes are taking place in the economic environment surrounding U.S. refiners: (1) crude oil supplies are coming from new sources and prices of foreign crude oils are rising sharply, (2) new environmental regulations are causing changes in product characteristics making refineries more costly, (3) domestic crude oil supplies are declining, (4) both crude oil and product prices are subject to controls, and (5) a recent sharp surge in oil demand has strained domestic refinery production capabilities. These conditions and the lack of a consistent government approach with respect to matters affecting refineries -- particularly long-term access to foreign supplies of crude oil and product import policies -- have made the outlook for investments in new refineries in the United States much more uncertain than it was in the 1960's.

A continuation of these conditions will create an increasing shortage of domestic refining capacity between now and 1985. Furthermore, there could be a future worldwide shortage of refining capacity available to supply U.S. markets, depending on economic and political conditions both here and abroad. While the Committee has not evaluated the ability of world refining capacity to meet the growth in both U.S. and non-U.S. world demand, the assumption is made that sufficient refining capacity will be built. However, it is felt that if petroleum product demands continue like the rapid growth which occurred during the last 1 to 2 years and if U.S. policies are not sufficiently responsive to the refining situation, adequate worldwide capacity may not exist. Some of the capacity to meet U.S. demand has already been constructed just outside the perimeter of the United States for the specific purpose of supplying U.S. demand for selected products.

A number of key factors have dictated the decisions made by some companies to establish refining facilities in perimeter locations. Some of these factors are:

- *To accommodate revisions in U.S. import quota restrictions:* Foreign crude oil could be imported without limitations into perimeter locations. Products could be manufactured

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This chapter was prepared prior to the issuance of the President's Energy Message to Congress of April 18, 1973, and does not take into account the oil import proclamation contained therein.

Crude prices and product values as used in this chapter were representative at the time of this study--and do not reflect conditions as prevailed during and since the period of the Arab oil embargo: unstable crude prices and product price stabilization by governmental regulation.

that were exempted from formal U.S. quota controls -- such as residual fuel oil for District I -- and exported to the United States.

- *For logistical considerations:* Natural deepwater harbors were available to accommodate larger, more efficient and economical tankers.

- *To minimize the risks associated with acquiring crude oil supply:* Foreign refinery locations frequently provided greater long-term access to necessary foreign crude oil supplies than did refinery locations in the United States.

- *To avoid environmental delays:* In recent years, environmental constraints in the United States have made foreign locations more attractive. Environmental obstacles have been less severe in the foreign perimeter locations in terms of building or expanding refining capacity compared to alternative U.S. locations. These offshore areas have low-density populations and less port siting problems.

- *To minimize overall costs:* Economic advantages favored refining operations in some perimeter locations compared to onshore U.S. locations. These included lower crude oil handling, transportation and operating costs and advantageous tax provisions and other industrial development incentives.

RELATIVE ECONOMICS*

To illustrate the relative economics of refining foreign crude oil domestically and offshore, an economic model was constructed and studies were made to evaluate different situations that might arise between now and 1985. Many of the cases concentrated on the situation in District I (due to the critical refinery shortage in that area) and on the likely refining combinations for meeting the demand. Other districts were also examined to determine the cost of meeting the demand district-by-district. Comparisons between District I onshore refineries and offshore refineries were made, and the costs of supplying environmentally acceptable fuels were examined.

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* *The illustrative economic model studies presented in this Chapter were prepared prior to the issuance of the President's Energy Message to Congress of April 18, 1973, in which the President removed by proclamation all existing tariffs on imported crude oil and products and suspended direct control over the quantity of crude oil and refined product imports. In place of the control system the President has initiated a license fee system. This report does not attempt to evaluate or comment on the President's Energy Message and is based solely on policies in effect prior to April 18, 1973.*

In addition to direct refinery-to-refinery comparisons illustrating the basic onshore/offshore cost differences, three energy scenarios were postulated to determine the overall effect on Districts I, II and III: (1) a product import scenario in which import quota controls continue and the growth of domestic capacity is projected from the responses to the survey questionnaire with foreign capacity making up the difference; (2) a national security scenario which brings all new capacity onshore; and (3) a zero growth scenario, an unlikely situation where all new capacity moves offshore. This section details the methodology of the model as well as numerous other combinations studied.

The principal assumptions used in the economic models are:

- Growth in product demand is based on the Initial Appraisal.
- Demand growth is to be satisfied in new 200 MB/CD refineries. (Actually, a substantial amount of product will be produced by expanding existing refineries.)
- Iranian light crude oil is representative of future crude oil supplies. The crude oil price is an assumed price for 1985. Recent dollar devaluation and negotiated changes between international oil companies and Middle Eastern countries indicate that this price ($2.50 per barrel) might be reached by the 1975-1977 period. If this price is exceeded, the effect will be to increase the per barrel cost of products from both onshore and offshore refineries. This increase will be almost the exact amount of the per barrel crude oil price increase.
- Crude oil import quotas are available at no cost.
- Crude oil is delivered to offshore (Caribbean) refineries in VLCC's and products are barged to the United States.
- Import duties on all products are assumed to be at 1972 levels.
- For domestic refineries, crude oil is delivered in VLCC's to an offshore deepwater transshipment port and thence by barge to the United States or (in the case of District III) in VLCC's to an offshore receiving terminal.
- Construction costs will increase 3 percent per year to reflect anticipated real cost increases in the construction industry.
- All dollar costs are expressed in constant 1972 dollars.
- Manpower cost is assumed to be effectively 28 percent higher in the United States than offshore (Caribbean).

- Expected product costs include interest on working capital and an assumed return on investment required on fixed assets. Although costs were computed for rates of return from 4 to 20 percent, costs are displayed at 10 and 15 percent rates of return for illustrative purposes. Rate of return is based on the discounted cash flow (DCF) method or internal rate of return method commonly used in the economic analysis of business projects.

- Future effects of inflation are not included.

- An income tax rate of 48 percent applies to onshore locations. No income tax is assumed for an offshore Caribbean location on the premise that refiners would be in a position to use tax concessions commonly available. However, offshore Caribbean costs with tax rates up to 28 percent are shown for purposes of comparison. In eastern Canada, the 49 percent statutory tax rate is assumed to be in effect.

These studies do not attempt to give finite answers on preferable locations either onshore or offshore. Each refinery location, of course, presents a special case with its own particular site, transportation, labor, environmental and other related operating situations. However, the studies do adequately show the order of magnitude of the differential costs of producing petroleum products between the general areas studied.

On the basis of these assumed data, it would be expected that to a large degree, the necessary refineries will be constructed offshore (except in the cases of Districts IV and V where suitable offshore locations are not readily available, but refineries supplying the U.S. West Coast from a Pacific Island or the West Coast of Latin America are not inconceivable). However, the government may conclude that other considerations -- military and economic security, balance of trade, and provision of jobs for U.S. citizens -- provide greater overall benefits for the national economy than the cost savings from using foreign refineries.

If overriding benefits require that new refining capacity be located in the United States, some differential incentives will be required to induce the domestic construction. Whatever policy is adopted, it should be clear and firm. If investors believe that government inducement to build onshore refineries is temporary, the economic attractiveness of doing so will be weakened. A program aimed at the lowest possible current product prices is not compatible with having ample domestic refining capacity. Policies that try to accomplish both of these objectives are ambiguous and are not likely to be effective.

The approach followed in conducting these illustrative studies was to define the expected demand growth between 1970 and 1985 for each PAD District, define an incremental crude oil of reasonably representative quality, construct an economic model encompassing all of the governmental, environmental, refining, transportation and other cost factors (including investment and operating costs), and display the results of various cases. The cases studied are listed on Table 30 and the more significant cases are discussed in the following.

TABLE 30

CASES EXAMINED WITH ILLUSTRATIVE STUDIES

Case	Location	Type Refinery	Nominal Size (B/D)
(1)	District I	Balanced Demand Refinery	200,000
(2)	District II	Balanced Demand Refinery	200,000
(3)	District III	Balanced Demand Refinery	200,000
(4)	District V	Balanced Demand Refinery	200,000
(5)	Onshore	Fuel Oil and Naphtha for District I only (ICOP)*	100,000
(6)	Offshore	District I Balanced Demand	200,000
(7)	Offshore	District I Balanced Demand	500,000
(8)	District I	Balanced Demand All 1% Sulfur No. 6 Fuel Oil	200,000
(9)	District I	Balanced Demand All 0.7% Sulfur No. 6 Fuel Oil	200,000
(10)	District I	Balanced Demand All 0.3% Sulfur No. 6 Fuel Oil	200,000
(11)	Combined	Balanced Demand for District I with Light Product Onshore and Fuel Oil Offshore with Excess Naphtha	400,000
(12)	District III	District I Balanced Demand	200,000
(13)	District III	District I Light Products and Half of District I Fuel Oil	180,000
(14)	Offshore	District I Fuel Oil Not Supplied in (13) Excess Naphtha	250,000
(15)	District I	District I Light Products and 8% of Fuel Oil	150,000
(16)	Product Import Scenario	Refer to text	
(17)	National Security Scenario	Refer to text	

*Imported Crude Oil Processing Facility (ICOP).

Supply of District I

A number of alternative supply possibilities were examined for meeting the increase in demand for petroleum products between 1970 and 1985 (see Table 31). District I is currently critically short of refining capacity and based on the recent refinery survey, little new capacity is planned for the future.

TABLE 31

PROJECTED GROWTH IN PRODUCT DEMAND—1970-1985

	District I		District II		District III		District IV		District V		Total U.S.	
	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%	MB/D	%
Mogas	1,137	26.67	1,155	42.54	507	25.70	99	32.46	517	30.36	3,415	31.16
Avgas	6	.14	6	.22	5	.25	3	.98	9	.53	29	.26
Special Naphtha	8	.19	6	.22	8	.41	—	—	3	.18	25	.23
Kero-Jet	642	15.06	341	12.56	139	7.05	49	16.07	513	30.12	1,684	15.37
Kerosine	20	.47	45	1.66	30	1.52	6	1.97	23	1.35	124	1.13
Distillate	564	13.23	311	11.45	132	6.69	58	19.02	151	8.87	1,216	11.10
Residual Fuel	1,450	34.01	316	11.64	124	6.28	36	11.80	304	17.85	2,230	20.35
Asphalt	78	1.83	139	5.12	60	3.04	23	7.54	61	3.58	361	3.29
LPG	138	3.24	254	9.36	111	5.63	30	9.84	71	4.17	604	5.51
Petrochem Feed	220	5.16	142	5.23	857	43.44	1	.33	51	2.99	1,271	11.60
Total	4,263	100.0	2,715	100.0	1,973	100.0	305	100.0	1,703	100.0	10,959	100.0
Percent of Total U.S.	38.9		24.8		18.0		2.8		15.5		100.0	

Throughout this section, the following definitions apply:

- *Balanced Refinery:* is one that produces a yield of products proportional to the growth in product mix projected between 1970 and 1985.
- *Light Oils Refinery:* is one that produces the required gasoline, distillate, and lighter fuels.
- *Fuels Refinery:* is one that produces primarily the residual fuels requirement with only that distillate and naphtha necessary to make the refinery viable.

Five alternatives for supplying District I are considered. Table 32 summarizes the relative costs of the five, and the following section describes them in detail.

TABLE 32

ILLUSTRATIVE RELATIVE COSTS FOR SUPPLYING DISTRICT I*
($/Bbl of Product in 1985)

Origin of Supply		10% DCF Rate of Return	15% DCF Rate of Return
Case 6	Offshore Balanced Refinery (Full Range of Products)	5.42	5.68
Case 1	District I Balanced Refinery	5.58	6.07
Case 12	District III Balanced Refinery	5.85	6.28
Case 11	Combination of a Light Products Refinery in District I and a Heavy Fuel Oil Refinery Offshore	6.08	6.49
Case 14	Combination of a Light Products Refinery in District III and a Heavy Fuel Oil Refinery Offshore	6.10	6.56

* These cost data include 1972 level U.S. import duties.

- *From an Offshore Balanced Refinery:* As restrictions on light product imports are eliminated or changed into purely economic constraints such as nominal duties, the likelihood increases that balanced refinery capacity will be exported offshore. To evaluate this possibility in connection with District I -- using 1972 duty rates, clean product shipping rates from offshore to onshore and offshore construction and operating costs -- Case 6 was constructed.

  This case shows that the cost of products are $5.42 per barrel and $5.68 per barrel at 10 and 15 percent DCF rates of return respectively (see Table 32). Consequently, offshore refining has an advantage in supplying District I by a cost of $0.16 to $0.39 per barrel. Figure 13 shows

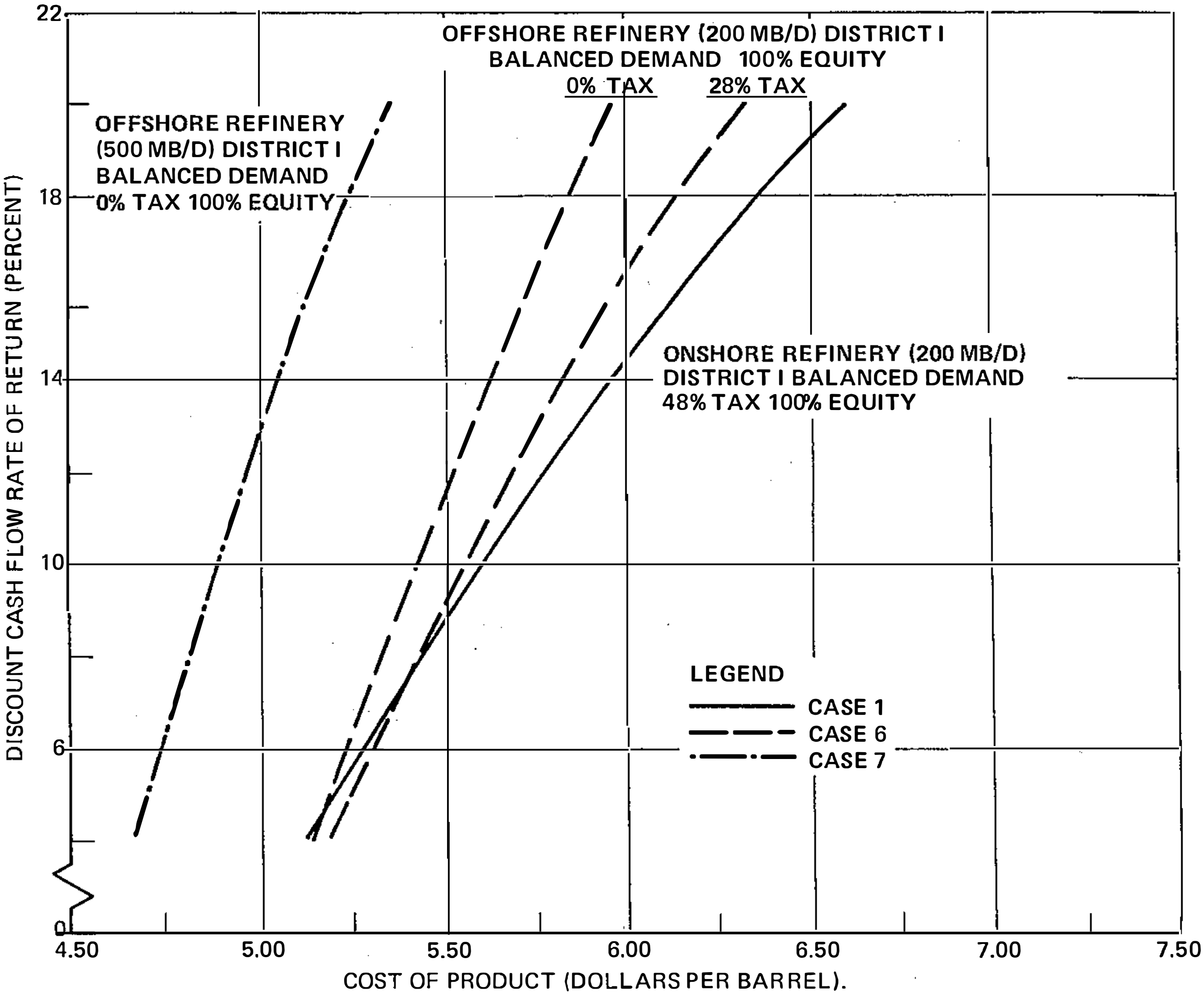


Figure 13. Comparison of Onshore *Versus* Offshore Refineries--District I Balanced Demand.

a range of rates of return and also shows a 28 percent tax rate alongside the zero tax rate. It should be noted that several of the cost differences relate to environmental restrictions, offshore being less rigid than they are onshore -- i.e., higher sulfur content plant fuel may be used and effluent treatment facilities are less sophisticated.

- *From a District I Balanced Refinery:* If a site were available, a 200 MB/CD refinery located along the East Coast would require an expenditure of at least $414 million and would produce products at an average cost per barrel of $5.58, assuming a 10 percent DCF rate of return on investment or $6.07 at a 15 percent rate of return (see Table 32). Between now and 1985, District I will need to add a capacity equivalent of at least 20 such refineries, if it is to meet its incremental product demands.

Crude oil for the assumed refinery was received in VLCC's in the Bahamas and transshipped to the East Coast in barges, which for the refinery represented a terminalling and transshipment cost of $0.28 per barrel. For further details see Case 1 on Table 33. The cost of products at various rates of return is shown on Figure 14. Tables 34 and 35 show the product yields of Cases 1-10 in District I and Districts II through V, respectively. The effect of investment leverage is illustrated on Figures 15 and 16. Currently, the average debt to equity ratio for 36 companies--both integrated and independent--is 30/70, but may well increase to the range of 40/60 by 1985. A wide range of rates of return is presented because it is impossible to produce a single rate that is or would be acceptable to every individual company.

- *From a District III Balanced Refinery:* Since District III has more refining capacity than other districts and has historically supplied much of the District I product demand--mainly by pipeline to the East Coast market centers--this case was studied to determine the cost of continuing the existing practice for a balanced demand. Case 12 (see Table 37) shows this can be done at a cost of $6.28 per barrel including allowances for light product and fuel oil transportation costs to District I. The receipt of crude oil was assumed to be in VLCC's via a LOOP or SEADOCK type project at a transshipment tariff cost of $0.15 per barrel.

- *From a Combination Light Products Refinery in District I and a Heavy Fuel Oil Refinery Offshore:* If the Mandatory Oil Import Program (MOIP) as it is now, remains in effect in 1985, there will continue to be an export of "fuel oil" refinery capacity, with balancing "light oil" refineries onshore. If these onshore refineries are located in District I, Case 11 (see Table 36) illustrates the effect of meeting the entire District I demand through a combination of optimized facilities for light products onshore in District I and for fuel oils offshore. This case has several special features--the offshore location is permitted to export some No. 2 oil to District I and, in addition, naphtha produced in excess of the U.S. petrochemical demand is exported to locations other than the U.S. mainland.

  Satisfying District I demand in this manner would require about 10 refineries in District I and the same number of refineries offshore. Each offshore refinery would produce about 33.5 MB/CD of excess naphtha and supply about 9.4 MB/CD of No. 2 oil to the East Coast. After adjusting the cost for the excess naphtha (at $0.06 per gallon) the weighted average cost of products (product value including a 15 percent DCF) is $6.49 per barrel (see Table 32), with a zero tax rate offshore and a 48 percent tax rate onshore. Consequently, this method of meeting the District I balanced demand is more costly to the end user than supplying District I from District III, or than building balanced refineries in District I or offshore.

TABLE 33

REFINERY CONFIGURATION TO MEET DEMAND

Unit (B/SD)	(Case 1) PAD I	(Case 2) PAD II	(Case 3) PAD III	(Case 4) PAD V	(Case 5) ICOP*	(Case 6) Offshore	(Case 7) Offshore	(Case 8–1% S) PAD I	(Case 9–0.7% S) PAD I	(Case 10–0.3% S) PAD I
Nominal Capacity	200,000	200,000	200,000	200,000	100,000	200,000	500,000	200,000	200,000	200,000
Crude Unit	215,561	206,279	218,750	213,380	108,293	217,408	531,250	214,880	215,412	217,618
Vacuum Unit	90,125	97,364	103,250	100,716	38,993	85,707	219,330	79,041	86,716	102,668
Reformer Pretreater	21,392	36,734	1,008	9,008	–	23,700	47,788	22,470	22,059	27,823
Reformer	30,030	46,824	18,129	27,754	–	31,645	70,291	29,096	30,446	36,830
Catalytic Cracker	66,010	113,952	86,870	85,306	–	62,193	196,418	73,083	65,924	48,679
HF Alkylation	6,381	9,646	7,121	6,902	–	5,510	6,504	5,463	5,630	4,483
Cat Cracker Desulfurizer	49,645	65,774	50,064	49,289	–	47,212	120,818	43,540	47,767	43,790
Distillate Desulfurizer	29,023	24,917	530	34,899	21,479	33,179	73,307	18,589	32,773	36,893
DAO Desulfurizer	25,968	14,178	20,563	23,616	9,407	24,695	63,197	22,627	24,986	20,582
SDA	30,551	22,530	33,701	32,690	11,067	29,053	74,349	26,620	29,395	24,803
Partial Oxidation	–	–	–	–	–	–	–	–	–	–
Sulfur Recovery	296	250	247	292	159	284	726	249	287	374
Hydro Cracker	–	–	27,221	17,030	–	–	–	–	–	–
Hydrogen Plant	–	–	50,688	28,068	7,907	–	1,119	–	–	–
Gas Oil Desulfurizer	–	–	–	–	–	–	–	–	–	11,911
Investment ($M)										
Onsite	218,680	240,879	211,544	219,441	71,348	222,632	350,299	212,228	218,399	230,400
Offsite	77,192	82,836	71,639	72,998	27,087	72,019	115,937	76,228	77,002	78,409
Effluent Control	5,939	5,446	5,250	5,060	2,984	3,235	8,411	5,920	5,935	5,993
Docks	16,048	27,130	28,770	18,436	8,067	22,958	61,200	16,008	16,047	16,204
Tankage, Crude	9,830	10,396	7,875	7,600	4,938	16,947	12,750	9,799	9,823	9,919
Tankage, Product	9,426	9,835	7,399	7,157	4,578	10,878	29,217	7,991	7,991	7,991
Offshore Tankage	14,486	–	–	–	7,277	–	–	14,440	14,476	14,017
Catalyst	2,125	3,388	1,515	2,079	–	2,229	4,608	2,073	2,165	2,479
Royalty	1,986	3,209	1,547	2,009	–	2,078	4,100	1,946	2,029	2,245
Total Investment	355,722	383,119	335,539	324,778	126,378	352,976	586,522	346,634	353,866	368,256
Working Capital	58,149	60,596	61,740	59,405	29,213	68,666	167,790	57,965	58,109	58,677
Total Funds	413,871	443,715	397,279	394,183	155,591	421,642	754,312	404,699	411,975	426,933
Expenses ($/CD)										
Crude Oil†	793,193	801,617	787,080	728,017	398,483	829,210	2,025,724	790,689	792,645	800,395
Butane	7,500	16,106	7,500	5,707	–	7,500	18,156	7,500	7,500	5,411
Refining	96,173	107,731	104,082	103,684	29,986	75,109	115,956	91,391	95,624	103,200
Total	896,866	925,454	898,662	837,407	428,469	911,819	2,159,832	889,580	895,769	909,006
Cost of Product ($/Bbl)										
Including 15% DCF Rate of Return	6.07	6.71	6.01	5.87	5.56	5.68‡	5.24§	6.00	6.06	6.19
Including 10% DCF Rate of Return	5.58	6.16	5.56	5.37	5.28	5.42	4.88	5.52	5.58	5.21

*Imported Crude Oil Processing Facility (ICOP).

†Offshore crude oil cost includes duty on products imported to United States.

‡Balanced District I demand at zero income tax rate.

§28 percent tax rate.

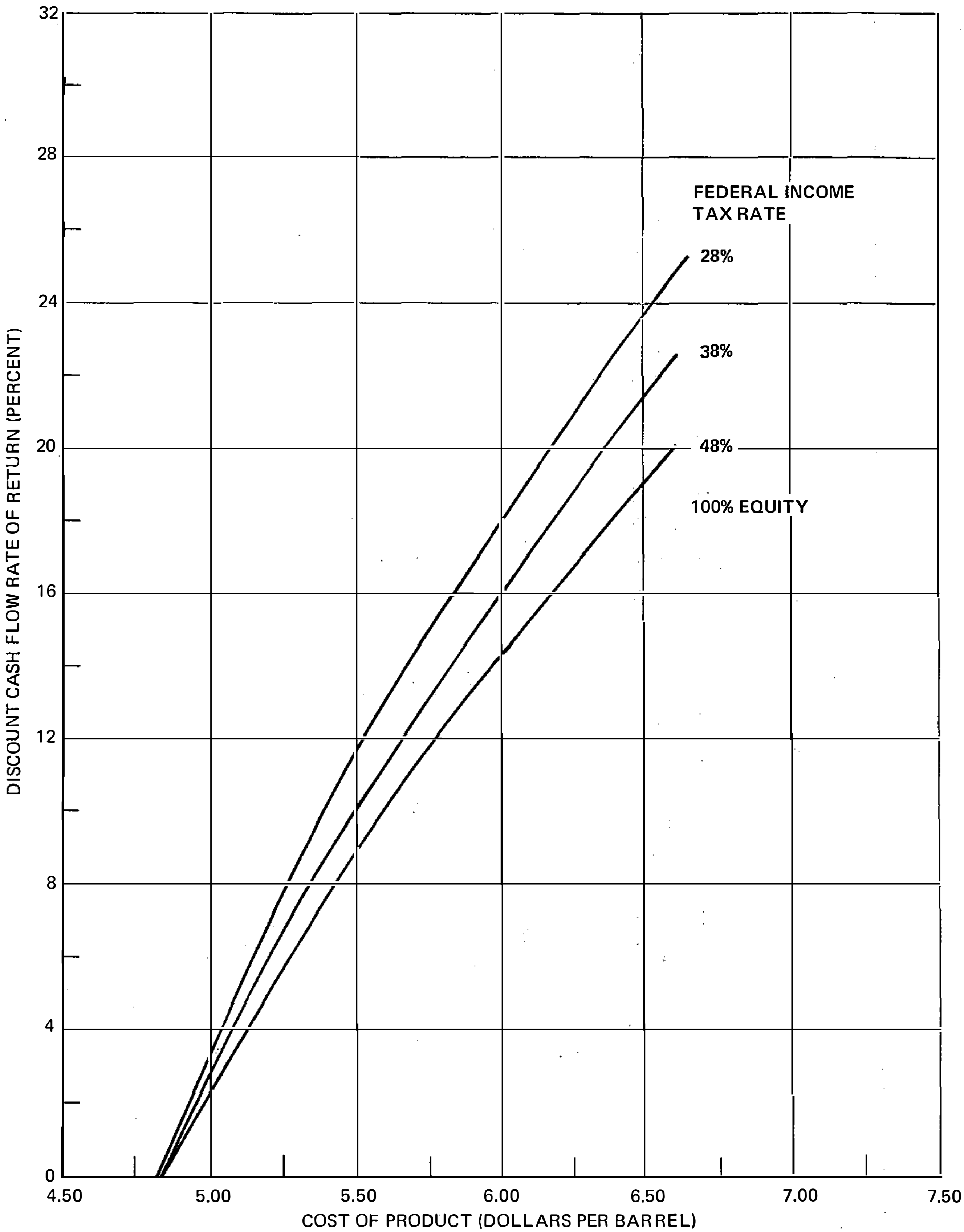


Figure 14. Onshore Refinery (Case 1)-- District I
Balanced Demand.

TABLE 34

REFINED PRODUCT YIELDS
(B/CD)

		District I Cases						
	% Yield*	(1) Balanced District I	(5) ICOP† District I	(6) Balanced Offshore	(7) 500 MB/CD Balanced Offshore	(8) 1% Sulfur Residual	(9) .7% Sulfur Residual	(10) .3% Sulfur Residual
Mogas	26.67	52,923	–	52,580	129,891	52,923	52,923	52,923
Avgas	.14	278	–	276	682	278	278	278
Special Naphtha	.19	377	–	375	925	377	377	377
Kero-Jet	15.05	29,885	–	29,690	73,347	29,885	29,885	29,885
Kerosine	.47	933	–	927	2,289	933	933	933
Distillate	13.23	26,253	–	26,083	64,434	26,253	26,253	26,253
Residual Fuel	34.01	67,488	68,025	67,051	165,639	67,488	67,488	67,488
(0.3% Sulfur)	(7.89)	(15,657)	(15,782)	(15,556)	(38,428)	–	–	(67,488)
(0.7% Sulfur)	(21.87)	(43,395)	(43,741)	(43,113)	(106,506)	–	(67,488)	–
(1.0% Sulfur)	(1.84)	(3,644)	(3,673)	(3,621)	(8,945)	(67,488)	–	–
(2.0% Sulfur)	(2.42)	(4,792)	(4,829)	(4,761)	(11,760)	–	–	–
Asphalt	1.83	3,631	3,659	3,608	8,913	3,631	3,631	3,631
LPG	3.24	6,429	–	6,388	15,780	6,429	6,429	6,429
Petrochem Feed	5.16	10,239	25,584	10,173	25,131	10,239	10,239	10,239
Total	100.00	198,438	97,268	197,149	480,031	198,438	198,438	198,438
Crude Inputs		206,938	103,961	208,711	510,000	206,284	206,795	208,817

*Based on projected District I demand.
†Imported Crude Oil Processing Facility (ICOP).

TABLE 35

REFINED PRODUCT YIELDS OTHER THAN DISTRICT I

	(2) District II		(3) District III		(4) District V	
	B/CD	%	B/CD	%	B/CD	%
Mogas	79,694	42.54	50,700	25.70	58,564	30.3
Avgas	412	.22	500	.25	1,022	.5
Special Naphtha	412	.22	800	.41	347	.1
Kero-Jet	23,530	12.56	13,900	7.05	58,101	30.1
Kerosine	3,110	1.66	3,000	1.52	2,604	1.3
Distillate	21,450	11.45	13,200	6.69	17,110	8.8
Residual Fuel	21,806	11.64	12,400	6.28	34,433	17.8
(0.3% Sulfur)	–	–	–	–	(28,752)	(14.9)
(0.7% Sulfur)	(12,895)	(6.88)	(2,959)	(1.50)	–	–
(1.0% Sulfur)	(6,047)	(3.23)	(5,055)	(2.56)	–	–
(2.0% Sulfur)	(2,864)	(1.53)	(4,385)	(2.22)	(5,681)	(2.9)
Asphalt	9,592	5.12	6,000	3.04	6,906	3.5
LPG	17,535	9.36	11,100	5.63	8,044	4.1
Petrochem Feed	9,798	5.23	85,700	43.44	5,768	2.9
Total	187,340	**100.00**	197,300	**100.00**	192,900	**100.00**
Crude Inputs	198,027		210,000		204,844	

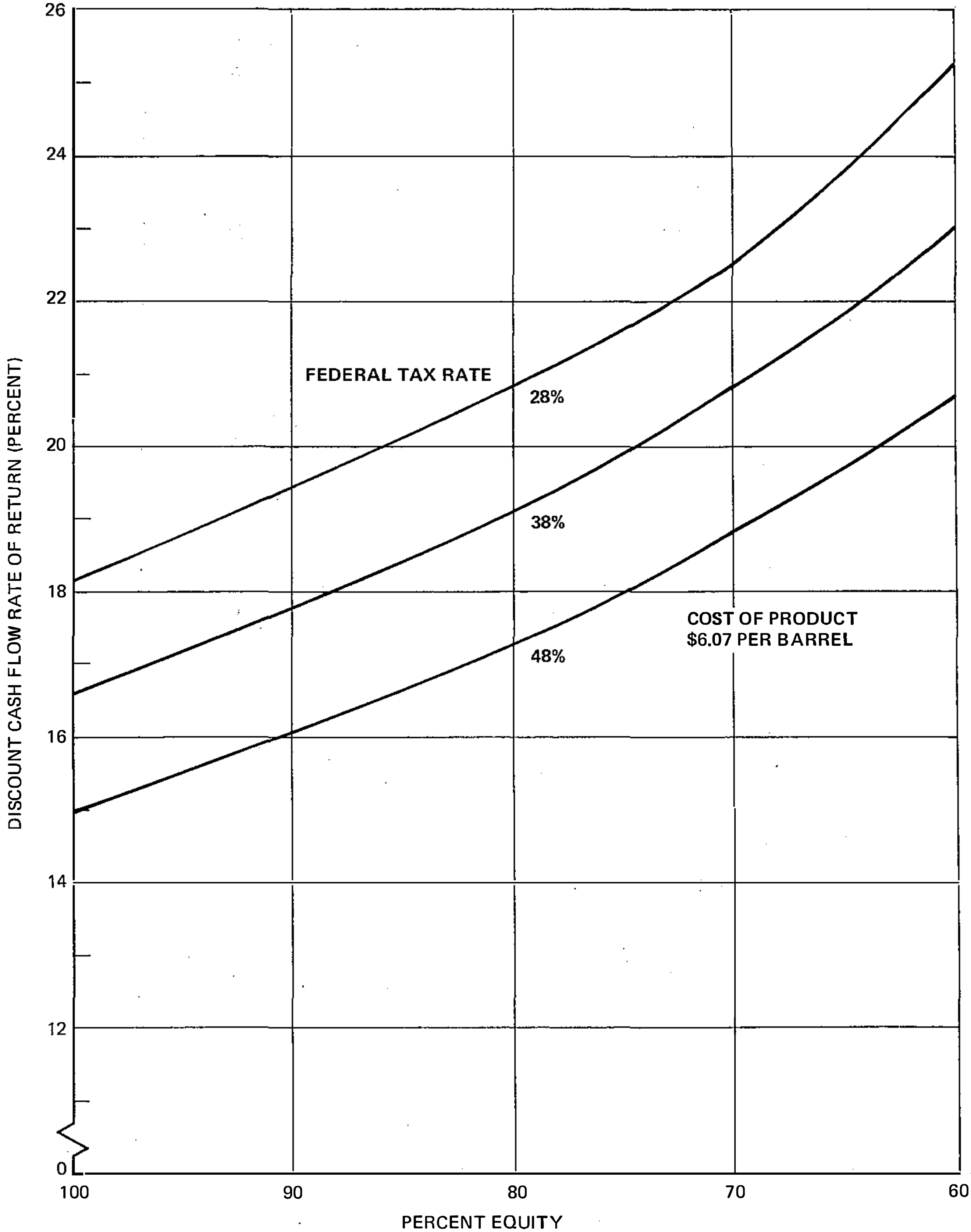


Figure 15. Effect of Debt on DCF at Constant Product Value--Onshore Refinery (Case 1) District I.

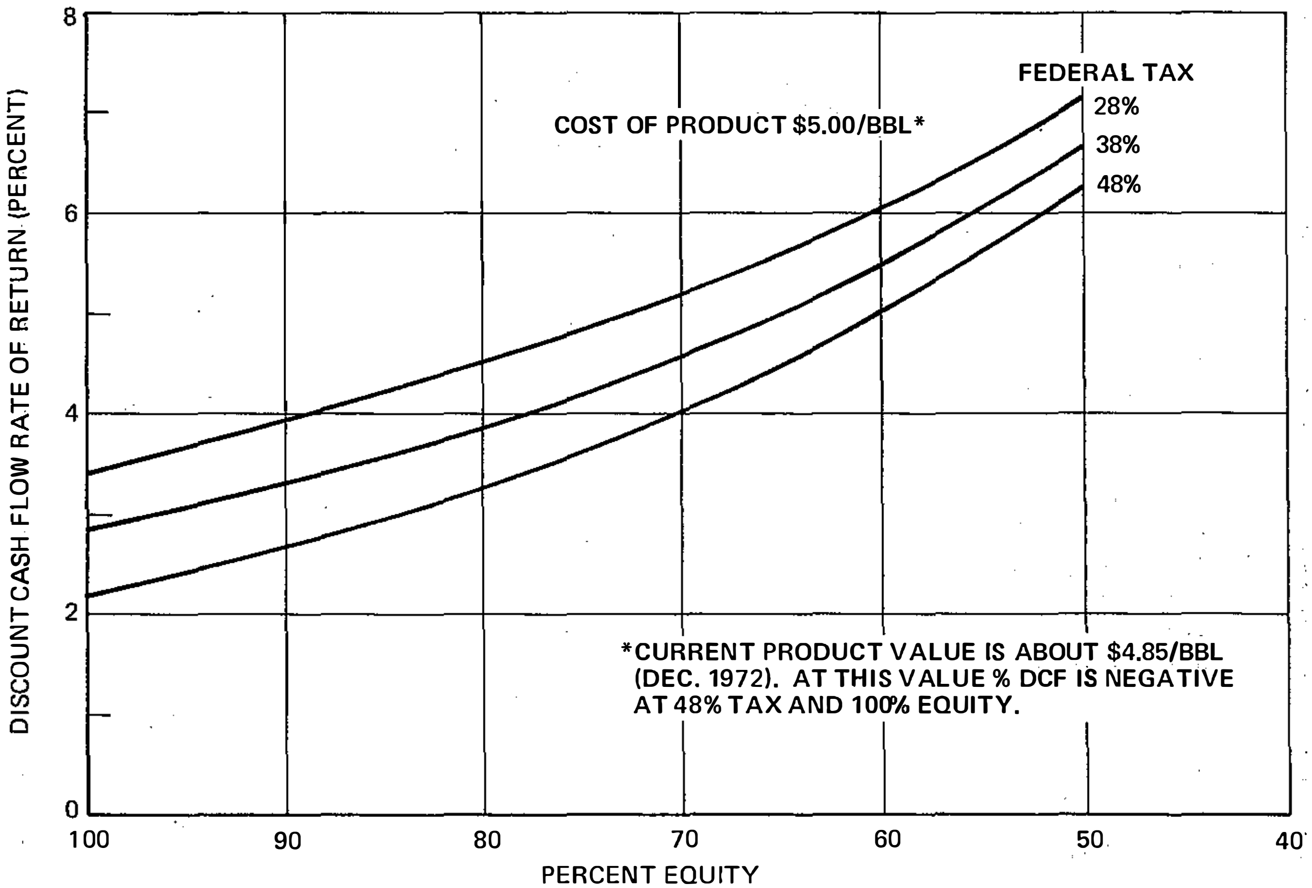


Figure 16. Onshore Refinery (Case 1)-- District I Balanced Demand.

The current MOIP tends to cause capacity to be constructed offshore as described in this case, primarily due to the fact that fuel oils are readily exported to the United States. In addition, this case is illustrative of the reason why naphtha is often available offshore -- its production is linked to fuel oil demand.

- *From a Combination Light Products Refinery in District III and a Heavy Fuel Oil Refinery Offshore:* Assuming that new capacity continues to be denied in District I but not in District III, then it is probable that District III will supply all of the light products for District I and about half the fuel oil, with the balance of the fuel oil originating offshore. This situation would result in the construction of about 21 refineries in District III and 4 refineries offshore--all dedicated to supply District I. Implicit in this situation is the added environmental exposure associated with transporting about 800 MB/CD of fuel oil from the Gulf Coast to the East Coast in shallow draft vessels or barges.

TABLE 36

REFINERY CONFIGURATION ONSHORE AND OFFSHORE TO MEET DISTRICT I DEMAND

(Current Mandatory Oil Import Program)

Unit B/SD	(11) Offshore	(11) Onshore
Crude Unit	201,584	286,012
Vacuum Unit	92,264	134,998
Reformer Pretreater	–	43,188
Reformer	–	92,220
Catalytic Cracker	–	66,367
HF Alkylation	–	11,193
Catalytic Cracker Desulfurizer	–	38,194
Distillate Desulfurizer	3,116	22,521
DAO Desulfurizer	26,585	5,312
SDA	31,276	6,249
Partial Oxidation	–	27,980
Sulfur Recovery (Long Ton)	402	367
Hydrocracker	–	61,054
Hydrogen Plant	2,413	56,300
Gas Oil Desulfurizer	50,824	–
Investment ($M)		
Onsite	127,437	331,945
Offsite	41,002	104,133
Effluent Control	3,000	7,880
Docks	21,287	21,307
Tankage Crude	15,714	13,042
Tankage Product	11,581	11,810
Offshore Tankage	–	19,220
Catalyst	–	6,205
Royalty	–	12,194
Total Investment	220,021	527,734
Working Capital	66,321	77,154
Total Funds	206,342	604,888
Expenses–Cash ($/CD)		
Crude Oil	709,058	1,052,431
Butane	–	–
Refining	41,975	179,906
Total	751,033	1,232,337
Cost of Product ($/Bbl)		
(Including 15% DCF Rate of Return)	5.06	6.77
(Including 10% DCF Rate of Return)	4.85	6.24

TABLE 37

SUPPLYING DISTRICT I FROM DISTRICT III AND OFFSHORE

Unit B/SD	(12) District III to Supply District I Balanced Demand	(13) District III to Supply District I Light Products Demand	(14) Offshore to Supply District I Fuel Oil Demand
Crude Unit	215,618	136,773	250,615
Vacuum Unit	89,996	64,557	118,290
Reformer Pretreater	20,730	22,115	—
Reformer	30,116	40,407	—
Catalytic Cracker	49,360	25,747	—
HF Alkylation	4,253	4,658	—
Catalytic Cracker Desulfurizer	49,574	15,337	67,470
Distillate Desulfurizer	35,223	15,525	—
DAO Desulfurizer	25,931	2,706	34,084
SDA	30,507	3,537	40,098
Partial Oxidation	—	12,938	—
Sulfur Recovery	299	177	522
Hydrocracker	—	26,790	—
Hydrogen Manuf.	—	27,371	26,149
Investment ($M)			
Onsite	184,900	182,231	145,052
Offsite	64,455	58,142	46,777
Effluent Control	5,175	3,233	3,729
Docks	28,358	17,988	26,465
Tankage Crude	7,762	4,924	19,536
Tankage Product	7,443	4,499	14,575
Offshore Tankage	—	—	—
Catalyst	2,062	2,704	—
Royalty	1,889	5,480	—
Total Investment	302,042	279,750	256,134
Working Capital	60,855	38,602	79,154
Total Funds	362,897	318,352	335,288
Expenses—Cash ($/CD)			
Crude Oil*	875,372	551,205	902,935
Butane	7,039	—	—
Refining	87,222	66,438	48,850
Total	969,633	617,643	951,785
Cost of Product ($/Bbl)			
(Including 15% DCF Rate of Return)	6.28	6.77	5.75
(Including 15% DCF Rate of Return)	5.85	6.24	5.59

*Offshore crude oil cost included duty on products imported to U.S.

As in Case 11, (Table 36), there is a surplus of approximately 38.7 MB/CD of naphtha at each offshore refinery. The combined economics of a light products refinery in District III (Case 13, Table 37) and a heavy fuel oil refinery offshore (Case 14, Table 37) with an adjustment for excess naphtha, indicates an average cost of $6.56 per barrel (see Table 32). By comparing Cases 11 through 14, it can be seen that producing some residual fuel oil in a refinery that primarily produces light oils tends to reduce the average cost of all products. However, product realization is also held at low levels because of lower cost offshore residual fuel oil. The net result is that, as things now stand, capacity is not build onshore for either light products or for residual fuel oil.

PRODUCT IMPORTS SCENARIO *VERSUS* NATIONAL SECURITY SCENARIO

Refiners are projecting that they could physically expand existing capacity in Districts I, II and III by about 4 MMB/CD by 1985. Since demand will increase by about 9 MMB/CD, the shortfall will have to be made up through new grassroots refineries or through product imports. Under the assumption that the 4 MMB/CD of expansion capability is constructed, the following scenarios were developed to supply the remaining 5 MMB/CD.

The Product Import Scenario is shown as Case 16 on Tables 38 and 39. These tables show the firm plans (extrapolated to 1985) for new or expanded capacity reported on the 1972 NPC survey of refiners. However, these plans do not necessarily imply that environmental approval has or will be forthcoming. Table 39 indicates a shortage of capacity in every district, except District III, and implies that large volumes of product imports will be needed from offshore. The economics of Case 16 show that the weighted average product value (Table 38) is $6.07 per barrel for Districts I, II and III.

The product import requirements for Districts IV and V are on the order of 944 MB/CD (see Table 39) and probably will have to come from somewhere in the Pacific or even the Persian Gulf. Due to the uncertainty of where this supply will originate, it is impossible to estimate the cost of supply.

Also shown on Table 38 are the calculated balance of trade and associated investment costs associated with the export of about 5 MMB/CD of refining capacity. The exported capacity might be in excess of what can physically be constructed at perimeter locations, but to the extent that offshore capacity is displaced further offshore (i.e., Europe or the Persian Gulf) the average cost will increase sharply, mainly due to transporting clean products in smaller size tankers over greater distances.

The National Security Scenario is shown as Case 17 (see Table 40). While there are many factors that transcend the refinery economics shown, Case 17 contemplates that government, industry and

TABLE 38

COST OF MEETING INCREMENTAL U.S. DEMAND BETWEEN 1970 AND 1985 IN DISTRICTS I, II AND III

	Product Import Scenario (Case 16)				
	Demand (MB/CD)	New Capacity (MB/CD)*	Number Refineries	Total Investment ($MM)	Balance of Trade Cost ($MM/Yr)
District I	4,263	—	—	—	8,463
District II	2,715	1,008	5	2,360	2,743
District III	1,973	2,973	16	6,196	4,032
Offshore	—	4,970	25	10,245	—
Total	8,951	8,951	46	19,245	15,238

Average Onshore Plus Offshore Cost of Products (Including 15% DCF Return on Investment) $6.07/Bbl

* See Table 39 for District Transfers and Imports.

TABLE 39

PRODUCT IMPORT SCENARIO—CASE 16
(MB/CD)

	PAD District				
	I	II	III	IV & V	Total
Capacity 1970	1,500	3,492	5,227	2,436	12,655
Capacity 1985	1,500	4,500	8,200	3,500	17,700
Increase	—	1,008	2,973	1,064	5,045
Demand Increase	4,263	2,715	1,973	2,008	10,959
Excess (Shortage)	(4,263)	(1,707)	1,000	(944)	(5,914)
District Transfers	—	1,000	—	—	1,000
Imports	4,263	707	—	944	5,914
Imports by Product					
Mogas	1,137	297	—	—	1,434
Jet	642	79	—	401	1,122
Distillate	564	70	—	50	684
Fuel Oil	1,450	86	—	340	1,876
Other	470	175	—	153	798
Total	4,263	707	—	944	5,914

TABLE 40

COST OF MEETING INCREMENTAL U.S. DEMAND BETWEEN 1970 AND 1985 IN DISTRICTS I, II AND III

	National Security Scenario (Case 17)*				
	Demand (MB/CD)	New Capacity (MB/CD)	Number Refineries	Total Investment ($MM)	Balance of Trade Cost ($MM/Yr)
District I	4,263	4,263	21	8,890	6,054
District II	2,715	2,715	14	6,430	3,609
District II	1,973	1,973	10	3,972	2,677
Total	8,951	8,951	45	19,292	12,340
Average Cost of Products (Including 15% DCF Return on Investment)				$6.24/Bbl	

* Assumes each district will meet its balance demand.

the public will conceive of and concur on policies that will result in all new refining capacity being constructed onshore with balanced capacity located in Districts I, II and III to meet the needs of each district. The cost of supplying District V under the same thesis is shown as Case 4 (see Table 33). The National Security Scenario product value is $6.24 per barrel or about $0.17 per barrel more than Case 16. However, the balance of trade impact is $12.3 billion, or about $0.88 per barrel less than the Product Import Scenario. Thus, while product values increase and end users pay slightly more for products, the effect on the Nation is positive by a very significant margin. In this case, as in all other cases, it has been assumed that crude oil quotas are available at no cost. Naturally, to the extent that such a condition does not prevail, the added cost would raise the cost of products made onshore and result in giving offshore locations a greater competitive advantage.

SUPPLEMENTAL ECONOMIC STUDIES

Light Products in District I

Refinery economics over the past 10 years favored the output of light oil products. This has meant increased conversion of heavier oil fractions to gasoline and home heating oil at increased levels of capital investment. In the event that future capacity increases follow the historical pattern (but not as add-ons to old capacity) in new refinery facilities, then Case 15 (Tables 41 and 42) illustrates the cost of producing predominantly light products to meet District I light oil requirements. The residual fuel oil yield was limited to 8 percent as this is approximately typical

TABLE 41

CONFIGURATION FOR DISTRICT I LIGHT PRODUCTS REFINING—CASE 15 (8% FUEL OIL)

Unit (B/SD)	Mogas Refinery
Crude Unit	149,885
Vacuum Unit	70,746
Reformer Pretreater	23,142
Reformer	47,454
Catalytic Cracker	30,667
Catalytic Desulfurizer	17,723
Distillate Desulfurizer	17,055
DAO Desulfurizer	13,616
SDA	23,728
Sulfur Recovery	161
Hydrocracker	28,460
Hydrogen Plant	27,110
Alkylation	5,442
Investment ($M)	
Onsite	217,544
Offsite	69,427
Effluent Control	4,130
Docks	11,166
Crude Tankage	6,835
Product Tankage	6,339
Catalyst	3,174
Royalty	2,862
Total Investment	321,477
Working Capital	40,433
Total Funds	361,910
Expenses ($/CD)	
Expenses (Cash)	
Crude Oil	551,528
Refining	100,797
Total	652,325
Cost of Product ($/Bbl)	
(Including 15% DCF Rate of Return)	6.93
(Including 10% DCF Rate of Return)	6.27

TABLE 42

REFINERY OUTPUT FOR DISTRICT I LIGHT PRODUCTS REFINING—CASE 15 (8% FUEL OIL) (Bbl/CD)

Product	Mogas Refinery
Mogas	53,342
Jet Fuel	30,119
No. 2 Oil	26,460
No. 6 Oil 2.0% Sulfur	4,800
1.0% Sulfur	3,800
0.7% Sulfur	3,246
LPG	3,510
Naphtha	4,510
Asphalt	3,660
Total	133,447

of the average now produced in U.S. refineries. The product value is $6.93 per barrel -- well above the current price these products would bring (i.e., $4.85 per barrel if such a refinery were located in northern Florida).

The use of northern Florida as a point of location comparison is arbitrary, but it represents a grassroots location where no refineries now exist. Any other location along the East Coast could have been nominated without introducing any substantial effect on the difference noted between required product value and current average prices. The point of concern remains, therefore, the very substantial difference between cost and price ($0.048 per gallon at 15 percent DCF). This difference needs to be closed before facilities which make light products can be considered economically attractive on the U.S. East Coast. Even if the required rate of return were halved (to 7½ percent DCF), the product value of $5.96 per barrel would be $0.025 per gallon more than the current (December 1972) weighted average price of products produced.

Economics of Size for Large Offshore Refinery

Case 7 on Table 33 attempts to show the magnitude of savings possible through economics of scale for a 500 MB/CD balanced demand refinery located in the Caribbean. Figure 13 shows the comparison with a smaller offshore facility meeting the same demand and for a District I refinery also meeting a balanced demand. Several Caribbean refineries are in the size range of 500 MB/CD although they are not balanced-demand type installations. However, large hydroskimming type plants (utilizing mixtures of low-sulfur and high-sulfur crude oils) are capable of producing fuel oils at much lower costs than shown in this study.

Consequently, as long as fuels made in large offshore plants which use combinations of crudes and processing operations have free access to the U.S. market, it will be most difficult for onshore refineries to justify building desulfurization capacity to produce low-sulfur fuel oils, regardless of what may happen to increase prices. On the other hand, to deny existing offshore fuel oil refineries now in operation access to the United States for fuel oil would represent an unfair restriction for those companies who made commitments to produce fuel oil in accordance with the MOIP.

Low-Sulfur Fuel Oil Costs

Considerable attention has been focused on the cost of manufacturing low-sulfur fuel oils. By comparing Cases 8, 9 and 10 (see Figure 17) the increase in average product value can be seen

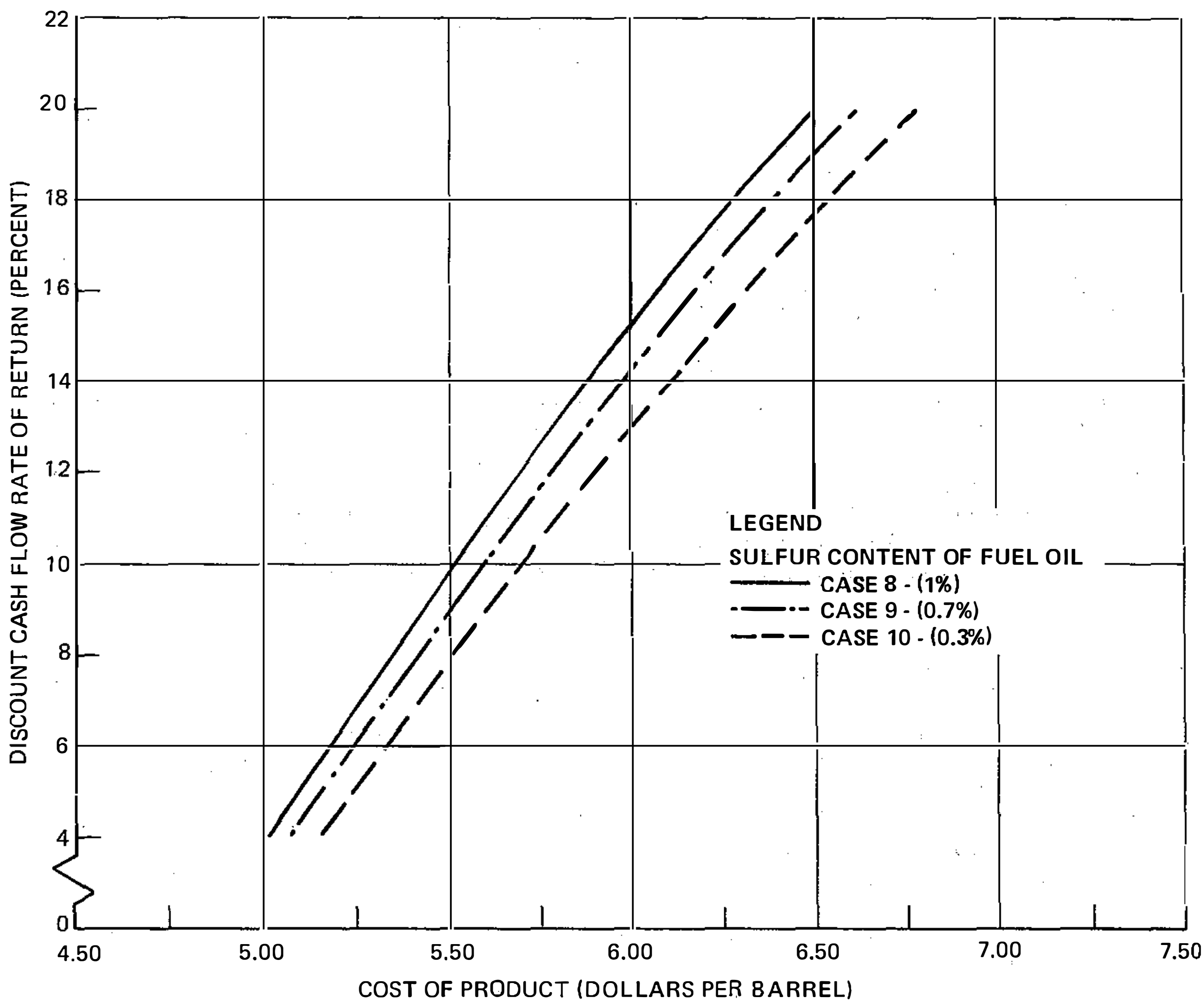


Figure 17. Effect of Reducing Sulfur Content in Fuel Oil--Onshore Refinery District I Balanced Demand.

as fuel oil sulfur levels decrease. Comparing these data with the yields and costs of Case 15 (see Tables 33, 34 and 35 *versus* Tables 41 and 42) it is possible to estimate the incremental cost of producing various sulfur levels of No. 6 fuel oil rather than only light products. These costs are shown in the following tabulation:

Percent Sulfur No. 6 Oil	15% (DCF) ($/Bbl.)
1.0	$4.09
0.7	$4.27
0.3	$4.67

These product values are for the special case in which a refiner decided to install a balanced demand type refinery rather than a light products refinery -- all for District I. They do not apply, however, unless the refiner is in a position to initially achieve a product value of $6.93 per barrel for light products -- certainly not the case under current conditions (1972) as explained earlier in this chapter. However, it can be seen that between Case 8 and Case 10, 1.2 percent more crude oil is needed to decrease sulfur in fuel oil from 1.0 percent to 0.3 percent plus a decrease in the volumetric heating value of 1.4 percent. Therefore, it takes 1.2 percent more crude and requires 1.4 percent more volume to satisfy a given energy demand to change from 1.0 percent sulfur to 0.3 percent sulfur in No. 6 oil.

Comparing the offshore portion of Case 11 and Case 14 (see Tables 36 and 37, respectively) with the foregoing item reveals that producing fuel oil offshore can range in cost between $5.06 per barrel and $5.75 per barrel, whereas producing fuel oil onshore, as discussed earlier, is much less. This would indicate that once product prices have reached a point where onshore facilities are justified for light products, it then becomes more competitive to manufacture fuel oils onshore than to make them offshore.

Investment Tax Credit as a Fiscal Incentive

There are several possible fiscal changes which might assist in improving onshore refinery economics: (1) a more rapid depreciation for new or expanded facilities, (2) an increase in the percentage of investment tax credit, (3) a flexible duty on imported products and crude or (4) some form of tax on offshore facilities. The last alternative is not apt to be effective since there would be no way to tax non-U.S. companies who might locate offshore and supplant existing U.S. investments. Some combination of the other three alternatives could provide a real inducement to bring capacity onshore. However, rather than evaluate each alternative separately, several cases were examined relative to the investment tax credit necessary to offset all of the cost difference between an onshore and offshore location for District I demands.

As a result of examining investment tax credits of 7 percent, 14 percent and 21 percent, it was determined that if the tax credit for new facilities were increased to 21 percent the rates of return curves would cross at 11 percent and a product value of $5.44 per barrel for onshore and offshore refineries. With a tax credit offered at this level -- say for the first 1 MMB/CD of capacity installed each year for 5 years -- there would probably be a steady reversal in the exportation of capacity, provided it becomes possible to obtain environmental approval of new plans without delay. With some combination of a lower investment tax credit, a modest increase in depreciation and a tariff or duty on products produced offshore, the desired result of increasing refinery capacity onshore could be achieved -- assuming the long-term security of crude oil supply is assured concurrently.

Conclusions and Assumptions

The principal economic conclusions of this study are (1) that the current product price structure is low in comparison with expected future product costs onshore and to a lesser extent offshore and (2) that the costs of producing products in new refinery capacity will be lower offshore than onshore. The following tabulation shows published prices as of December 1972 for the additional products that will be required between and by 1985 (expressed in dollars per barrel of product) and the costs of making those products in a new refinery in the United States and in a new refinery offshore. Costs include an assumed 10 percent and 15 percent DCF rate of return on capital invested for facilities.

	$/Bbl of Product	
Additional demand in 1985 at 1972's prices	$4.85	
Cost of additional demand:	10%(DCF)	15%(DCF)
in a domestic refinery	$5.68	$6.07
in an offshore refinery	$5.42	$5.68

If permitted to function, the forces of a free, competitive marketplace might be adequate to cause the expansion or new construction of some of the necessary refineries at the lowest cost location -- probably offshore. Considering, however, the enormous magnitude of the potential shortfall in domestic capacity and the fact that a completely free uncontrolled market is unrealistic to anticipate, there will need to be programs that recognize other considerations--military or economic security, balance of payments or providing jobs for U.S. citizens--and provide greater overall benefits for the economy other than cost savings from using foreign refineries. These overriding benefits may require that new refining capacity be located in the United States. In such a case, further inducement or some form of product import control will be required. Whatever policy is adopted, it should be clear and quantitative.

If investors believe that government inducement to build onshore refineries is temporary, the economic attractiveness of doing so will be weakened. Any benefits, over and above those needed to reduce the costs of onshore refineries, would eventually be passed on to consumers in the form of lower prices.

The implications of refining cost differences between offshore and onshore locations under various conditions are clearly illustrated in terms of District I supply. The same principles apply in other districts, but more alternative supply patterns are possible for District I.

Assuming that there are no controls on prices and that a zero tax rate offshore can be achieved, the supply costs as shown lead to the following conclusions:

- *Assuming refineries can be built in District I and imports of light products are prohibited:* New balanced refineries will be built in District I and will save consumers about $0.42 to $0.50 per barrel over bringing heavy fuels from offshore. The term "balanced refinery" refers to a refinery with a product slate of both light and heavy products proportional to the projected growth in product demands. To assure the production of low-sulfur heavy fuel oil in District I, it might also be necessary to limit its import from specialized units, such as low-sulfur crude oil topping plants.

- *Assuming refineries can be built in District I and imports of light products are permitted:* Balanced refineries will be built offshore to supply District I demands at a saving of $0.16 to $0.39 per barrel over an onshore, balanced refinery. In other words, a cost disadvantage of $0.16 to $0.39 per barrel over and above the crude oil import quota cost must be overcome if the refineries are to be built in the United States.

- *Assuming refineries cannot be built in District I and light product imports are prohibited:* There would be a slight advantage of $0.25 to $0.28 per barrel to supplying District I from balanced refineries in District III instead of from light product refineries in District III and heavy fuel oil refineries offshore. As previously noted, it might also be necessary to prevent fuel oil imports from low-sulfur crude oil topping plants.

- *Assuming refineries cannot be built in District I and light product imports are permitted:* Balanced refineries would be built offshore to supply District I at a saving of $0.43 to $0.60 per barrel over an onshore, balanced refinery in District III. In other words, a cost disadvantage of $0.43 to $0.60 must be overcome if the refineries are to be built in the United States in the event that they are prohibited in District I.

Offsetting the cost disadvantages of onshore refineries, the Nation's economy would benefit from the creation of U.S. jobs, savings in the balance of trade and a more secure refining system. Again in terms of District I supply, Table 43 illustrates where the differences between expected offshore and onshore costs occur.

TABLE 43

ILLUSTRATIVE COSTS OF ONSHORE VS. OFFSHORE REFINERIES TO SUPPLY DISTRICT I GROWTH IN DEMAND
($/Bbl of Product in 1985)

	Origin of Supply		
	Onshore		
	District I	District III	Offshore*
Crude Oil in Persian Gulf†	2.65	2.63	2.69
Transportation and Terminalling‡	1.28	1.21	1.00
Duty	0.11	0.11	0.29
Operating Costs	0.48	0.45	0.38
Product Transportation	–	0.51	0.27
Interest on Working Capital	0.08	0.08	0.10
Marketing Expense	0.05	0.05	0.05
Income Taxes§	0.52	0.45	–
Return on Refinery Investment ‖	0.90	0.79	0.90
Total (15% DCF Rate of Return)	6.07	6.28	5.68
Total (10% DCF Rate of Return)	5.58	5.85	5.42

* The tabulation of costs shown in this table for an offshore refinery is not based on any particular location, nor are there currently any offshore refineries making the assumed "balanced" District I slate of products. Current offshore refineries are of the hydroskimming type, feeding mixtures of low-sulfur and high-sulfur crude, primarily producing fuel oil for the U.S. market. Consequently, these costs are not intended to display actual circumstances of current offshore conditions.

† Prices of crude oil in the Persian Gulf are the same. Figures in the table differ because they are expressed in dollars per barrel of product, and product yields vary from location to location. Costs include butane purchases and exclude cost of acquiring import quota.

‡ Shipping at Worldscale 70 rates. Oil moves to District I by VLCC to a Caribbean terminal and thence by barge to the United States. District III uses VLCC's and a man-made deepwater port.

§ 48-percent tax rate onshore and zero offshore. It is assumed that a refiner offshore will make full use of tax concessions.

‖ 15-percent rate of return. Return is related to estimated refinery investments. Offshore refinery investments include a power plant which onshore refineries do not have.

It can be seen that several cost variations exist between onshore and offshore refineries. In general, the lower crude oil handling costs and lower operating costs offshore just about offset the duty on products imported into the United States. In addition, offshore refineries frequently enjoy tax advantages.

Because of the assumption that crude oil import licenses are available at no cost, these studies show that providing refiners with free access to foreign crude oil will not, by itself, be enough of an incentive to cause new grassroots refinery construction onshore. Supplemental incentives or programs, such as firm restrictions on product entry, are required to ensure onshore construction.

If foreign taxes are assumed to be higher, or if the rate of return is assumed to be lower, the $0.39 per barrel advantage of foreign refineries shown in Table 43 will be less. These effects are illustrated in Table 44.

TABLE 44

SENSITIVITY OF PRODUCT COST TO INCOME TAX RATE AND RATE OF RETURN
($/Bbl of Product in 1985)

	Advantage of Offshore Refinery over District I	
	10% DCF Rate of Return	15% DCF Rate of Return
0% Tax Rate Offshore	0.16	0.39
28% Tax Rate Offshore	0.05	0.17
48% Tax Rate Offshore	(0.02)	(0.02)

The illustrative economics of a refinery located in eastern Canada (see Table 45) show quite a different set of economics than the cases previously described. In eastern Canada, the current income tax rate is 49 percent and, in addition, there is a statutory $0.04 per barrel environmental tax now applicable. As indicated by Tables 44 and 45, when the perimeter location income tax rates are comparable to domestic U.S. tax rates, the economic advantage of offshore locations tends to disappear *vis-a-vis* an onshore location.

From the work done in this study, it would appear that any type of grassroots refining facility located offshore which has the same cost opportunity of acquiring crude oil can manufacture a comparable slate of products cheaper than a domestic refinery, provided an effective low tax rate is obtained offshore.

As has been shown, a balanced offshore refinery maintains an economic advantage even it if pays duty on the products it exports to the U.S. East Coast. Consequently, even with free access of crude oil into the United States an offshore location would have an economic advantage over a U.S. location, if product imports are permitted from the offshore location. Naturally, any added costs for the onshore location such as a crude oil tariff, crude oil ticket cost or crude oil auction cost simply worsen the cost disparity and create greater pressures to export capacity and increase light oil product imports.

TABLE 45

ILLUSTRATIVE COSTS OF EASTERN CANADA REFINERY*

	$/Bbl of Product in 1985
Crude Oil in Persian Gulf	2.63
Transportation and Terminalling	1.10
Duty Crude and Products	0.29
Operating Costs	0.31
Product Transportation†	0.20
Interest on Working Capital	0.10
Marketing Expense	0.06
49% Income Tax	0.52
Return on Investment (15% DCF Rate of Return)	0.91
Total	6.12
Pollution Tax	0.04
Total (15% DCF Rate of Return)	6.16
Total (10% DCF Rate of Return)	5.76

* Estimated from existing operations; hence the product slate is not wholly consistent with the product slate projections used to develop Table 43.

† At Worldscale 125 rates.

If product imports are not permitted (assumption is that they would be frozen at 1970 levels) and free access of crude oil is permitted to the United States, then the economic forces at work are primarily U.S. refining economics per se, rather than competition from foreign locations. In this case, we find that the cost of producing products relative to the current price levels for products would provide virtually no return on investment incentive for a refiner to install balanced capacity, as explained earlier.

Consequently, the only capacity increase that would possibly be stimulated by a free access of crude oil program would be that which could be undertaken as debottlenecking of existing facilities in connection with producing higher valued products such as gasoline, jet fuel, kerosine, and distillate. Debottlenecking feasibility is highly dependent on each particular refinery installation. Without a detailed analysis of each refinery, it is difficult to estimate how much could be undertaken in each PAD District. However, if those products that are imported attract significantly higher duties than at present, then free access of crude oil would greatly enhance the possibility of new capacity onshore.

INCOME TAXES

The difference between the U.S. and foreign taxes can be a significant element in determining the location of a new refinery. Of all the kinds of taxes, income tax is the most important. It can often be as much as 20 times the total of other taxes.

The tax structure in several illustrative countries where U.S. refining capacity might be built has been examined for this report. In several instances, rates of income tax and the related tax on dividends (which a foreign subsidiary would be expected to pay to its parent) are in the 40 to 50 percent range. The taxes in these countries are comparable to those of the United States.

In several other countries, however, there is either no income tax or the government, in an effort to stimulate economic development, has offered tax holidays or special tax allowances (such as fast depreciation). These areas have a significant advantage over the United States, not only because of the favorable taxes, but also because of the kind of investment climate that such inducements suggest. Experience indicates that the tax situation may vary from time to time. In some countries special negotiations are possible and refiners will find that they may be able to develop tax concessions particularly suited to their operations. On the other hand, as countries achieve their development goals, or find their economies unbalanced by the inflow of refining capacity, tax inducements to new investment are likely to be stopped.

Table 46 shows the possible variations in tax rates on refining projects in selected perimeter areas outside the United States. Summaries of the tax structure of several countries are detailed in Appendix G (Tables 68-75).

PRICE CONTROLS

Wage and price controls have come at an unfortunate time for the domestic refining industry. Prices have been frozen at levels which are inadequate for justification of new refining capacity appropriately designed for the 1970's. The disparity between product prices required for acceptable economics on new refinery capacity and the level of prices allowed under the current controls is so wide that the details of the control machinery are not really important. The situation is that controls are intended to maintain the status quo (if controls function perfectly) rather than correct any economic imbalances. There are only two alternatives for the future. If present controls are retained, U.S. refining capacity cannot economically expand. If U.S. refining capacity is to expand, then price controls will have to be removed, or at least relaxed, with the expectation of refinery gate product values rising.

Prevailing Price Levels at Freeze

Just how it came about that permitted price levels are insufficient to support new refinery investment is probably a

TABLE 46

INCOME AND RELATED TAXES ON A REFINERY PROJECT
IN SELECTED COUNTRIES
(Dollars of Tax per Dollars of Pre-tax Profit)

	Amount of Tax	
	Regular	With Incentive
Aruba and Curacao	$ 0.50	$ 0.21
Bahama Islands	0	0
Guadeloupe	0.35	0
Jamaica	0.57	0
New Brunswick, Newfoundland	0.50	0.43
Puerto Rico	0.50	0
Trinidad and Tobago	0.50	0
Virgin Islands	0.50	0

Note: The taxes shown in this table are illustrative only. They include income and profits taxes and taxes on dividends paid. There are numerous variations in tax concepts from country to country which have not been examined in detail.

Tax incentives offered by the different countries also vary depending on the project, how it's organized, and the circumstances in the country at the time. They frequently have time limits. The taxes in the "With Incentive" column are an indication of the lowest tax rate that might apply, at least for a few years of the project's life. (Those figures in this column which are greater than zero reflect special known instances of negotiated rates and are not intended to be indicative of any future situation.) It is assumed that a refinery operator's overall tax affairs can be so organized that the tax savings can actually be realized.

separate study in itself. Some factors which may have had some bearing are as follows:

- Product values of mid-1971 were still influenced primarily by the economics of processing incremental crude in an environment of surplus refining capacity. Profits at that time and during the several previous years were too low to justify refinery expansions. Thus, controls happened to fall at the wrong point in the product price-refinery construction cycle relationship.

- The scope of facilities required for new refinery capacity is greater and more costly than pre-1971 facilities. Refiners were in the process of assessing the impact of increasingly difficult product quality and plant effluent standards on refinery investments. Clearly, 1971 product values did not represent recovery of costs of doing business under the future ground rules.

- A rapid escalation in construction costs between 1965 and 1971 resulted in further discouragement for building new refining capacity. Controls came at the end of a period when cost escalation had outrun the economics of technological improvements, productivity and scale and before product prices could adjust to reflect the increase in costs.

Cost-Price Squeeze

The economic environment in which refiners find themselves has been one of steadily increasing costs without compensating changes in product price. The costs for labor, employee benefits, materials, supplies and utilities have been steadily increasing. Traditionally, petroleum and other energy has been supplied to Americans largely from domestic sources at relatively low costs. The latter point is demonstrated by the movement of both gasoline and crude oil prices relative to other price trends.

For example, over the 1960-1971 period, gasoline prices, including sharply increased excise taxes, rose by less than half as much as the consumer price index for all items (Figure 18). The increase in gasoline prices over that period amounted to 15 percent. This compares with a 37 percent increase for all consumer items and a 34 percent rise for necessities such as food and clothing.

Similarly, petroleum wholesale prices have lagged behind the rise in wholesale prices generally since 1960. From 1960 to 1971, the price index for all commodities rose by 20 percent, while crude oil prices increased by 15 percent and gasoline prices by only 4.5 percent (Figure 19).

Operating costs for each refinery vary widely depending upon the size of the refinery, the type of crude oil being charged, the type of products being produced and the specifications for the products. As an illustration, the average hourly earnings in the petroleum industry (see Figure 20) are indicative of the increases in costs experienced over the last 11 years.

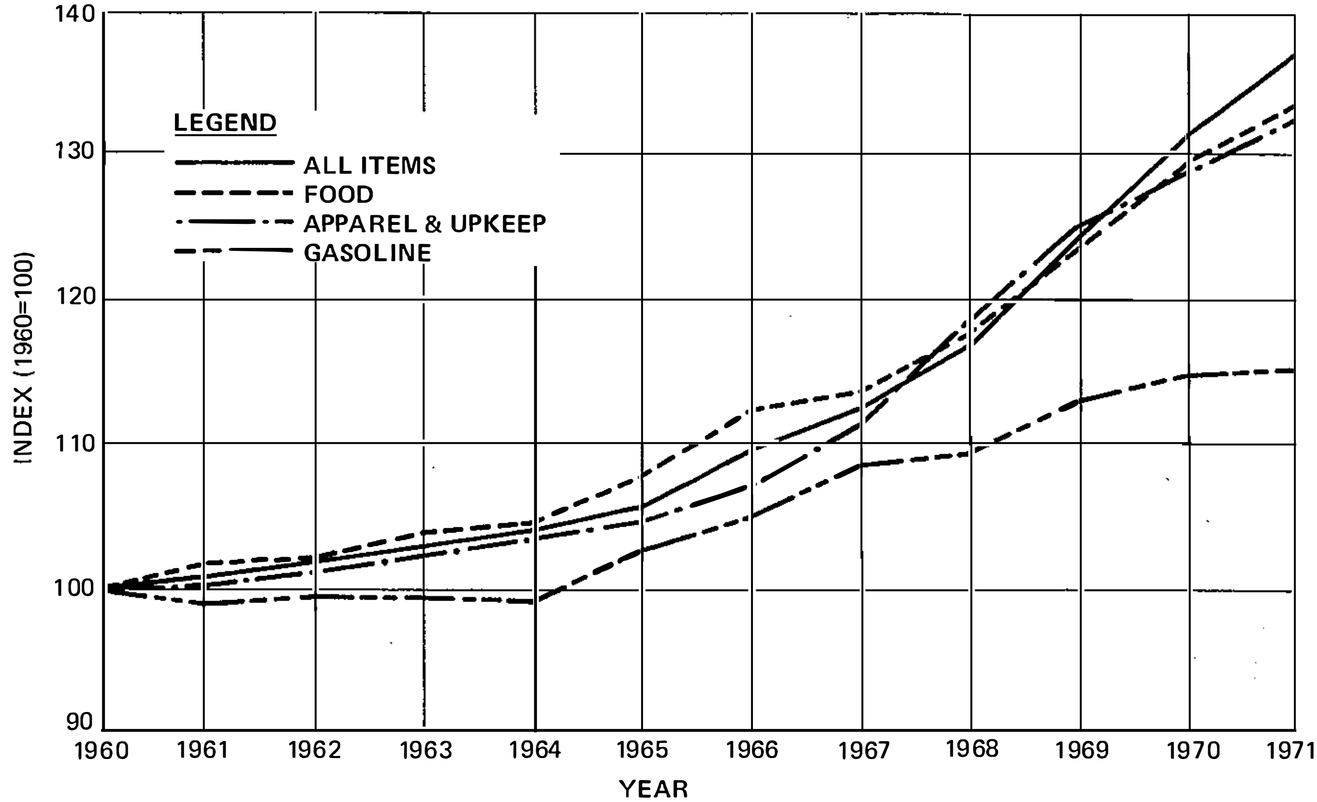
In brief, the U.S. energy situation in the past has been characterized by plentiful domestic supplies at relatively low costs. This availability of low-cost energy, particularly petroleum energy, has sparked an economic growth thrust that is unparalleled in world history.

CRUDE OIL SUPPLY

The problem of certainty of quality and quantity of crude oil to meet continuing U.S. needs is very large and complex. Important parts of the problem are phsyical, economic, financial and finally political. It is essentially a world problem and involves the demands of other nations, most importantly Western Europe and Japan, and the supplies available which are concentrated in relatively few parts of the world.

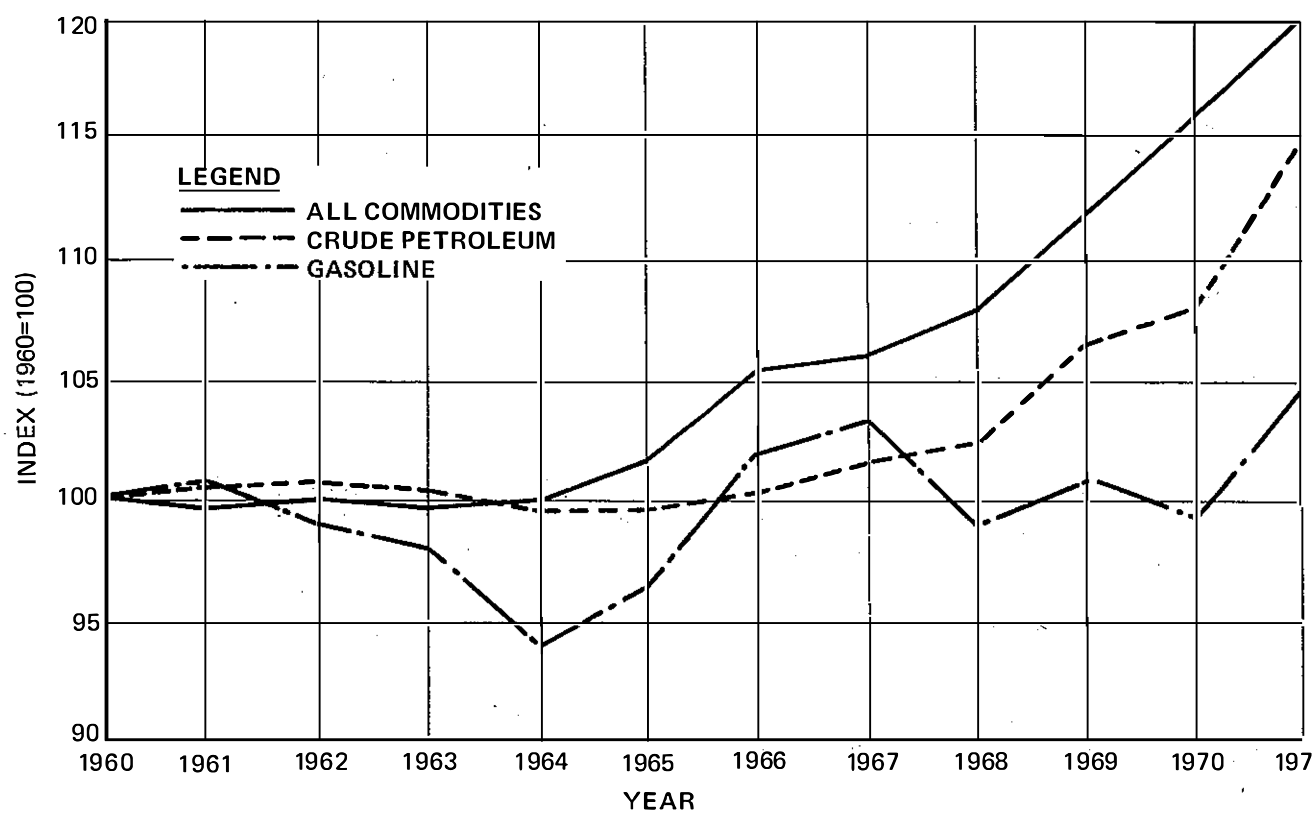
Physical Factors

Near-term production of crude oil within the United States has peaked. Much oil remains to be discovered in the United States; additional oil can be recovered from known deposits by secondary and tertiary methods if appropriate incentives exist. Because of



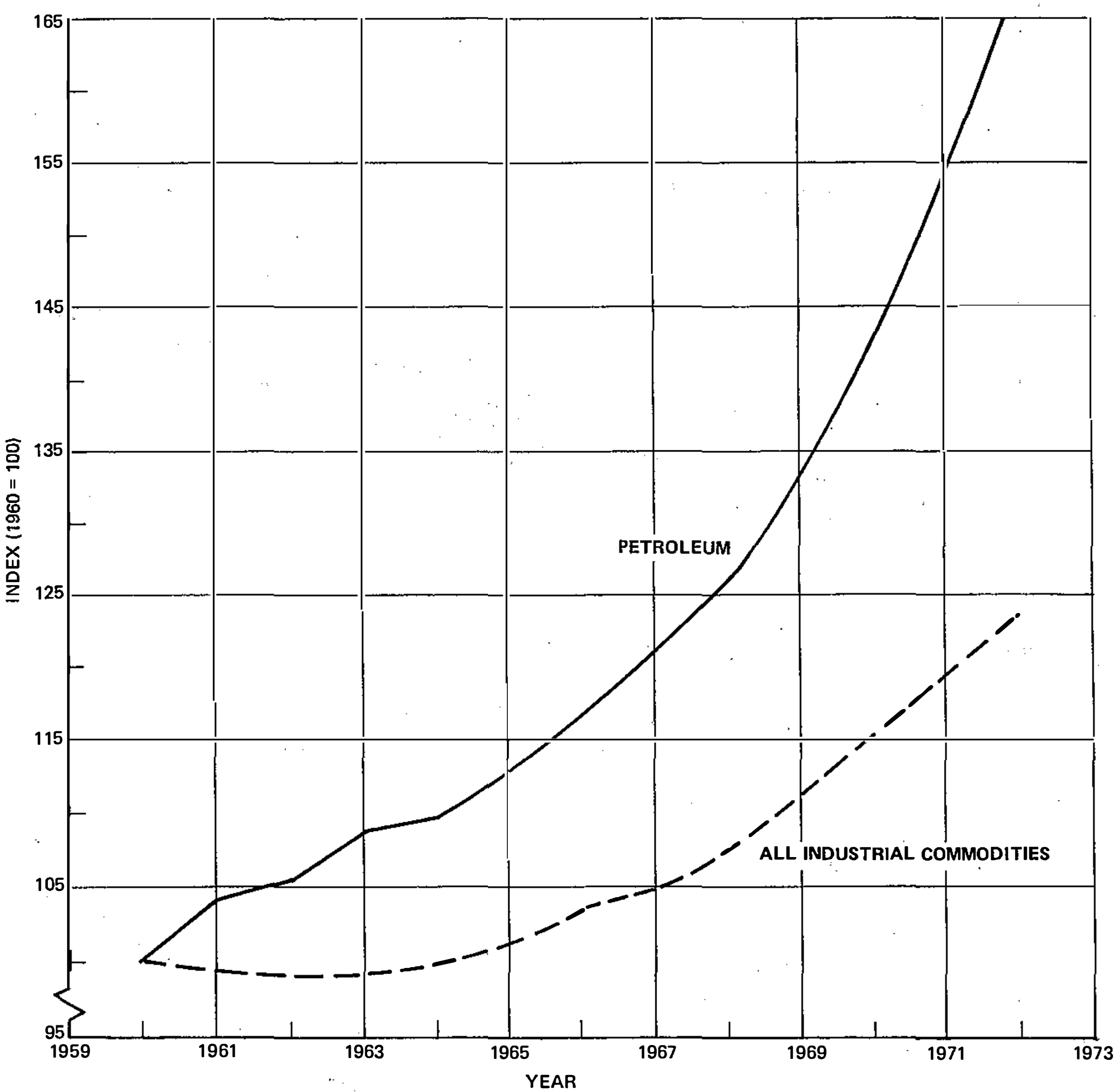
Source of Basic Data: U.S. Department of Labor

Figure 18. Consumer Price Trends.



Source of Basic Data: U.S. Department of Labor

Figure 19. Wholesale Price Trends.



* U.S. Department of Labor, Codes 131 and 132.

Figure 20. Average Hourly Earnings for Petroleum.*

this potential for future oil production, the United States will not become wholly dependent on others for oil, but the rate of accumulation of new supply within the United States will probably be slower than the rate of consumption. As a consequence, we may be required to import an increasing proportion of our consumption of crude oil or the products made from it. We imported 25.9 percent of required oil supply in 1971. As discussed in U.S. Energy Outlook, depending on whether we find oil at a high rate or low rate, we may need to import as much as 65 percent of our supply by 1985.

Since Canadian supplies are incapable of supplying Canada's needs and ours too, most of the imported crude oil must come from overseas by tanker. Because South American sources are limited, much of any additional crude oil must come from the Middle East and Africa. The economic incentive to transport the oil in large supertankers generally exceeding 200,000 deadweight tons (200 MDWT) is great. Ecological considerations also tend to favor use of large tankers since the number of transporting events is reduced, diminishing the potential for spills especially from collision in congested waterways. The rivers and harbors of the United States, with the exception of a portion of the coast of Maine and a part of Long Island, do not have an adequate depth to handle these large vessels. We will need, therefore, to develop specially designed ports for off-loading supertankers in the Eastern Seaboard, Gulf Coast and West Coast areas. Pipelines must then be constructed to deliver oil from the water's edge to refining centers.

Economic Factors

The finding of crude oil, as well as its recovery by secondary and tertiary means will be increasingly more expensive both within the United States and abroad. The problem is much larger than one of general inflation of costs. It is axiomatic that man seeks the easiest task first, and easy-to-find crude oil has already been discovered. Newer discoveries of crude oil are and will continue to be found in increasingly hostile environments -- in the arctic areas of Alaska, in the jungles of Africa, in the deserts and in deeper and deeper offshore waters. Moreover, in the United States, new discoveries will be in much deeper strata or in much deeper water, both of which require a geometric increase in expense to achieve the result. Whether these investments are made overseas or at home, the price of crude oil must reflect the cost of discovery and production, cost of capital and some profit incentive, or the investment required will be unavailable.

A precise evaluation of capital requirements for tank ships hinges upon the accuracy of projecting supply sources. However, if it is assumed that our total waterborne oil requirements in 1985 were to originate in the Persian Gulf, a fleet of at least four hundred 200 MDWT tankers would be required. This implies an investment of some $14 to $16 billion for ships by 1985. In order to provide incentives for such investments -- the cost of constructing and operating these tankers, the crude oil pipelines to refineries and the supertanker ports -- must ultimately be recovered from the consumer by virtue of the price mechanism.

The problems and economics of storage of large quantities of crude oil as a hedge aganist political interruption of supplies are not only those of the industry but also vital to the well-being of this Nation. This need for storage of material vital to the working of the U.S. economy is a national security consideration.

An additional economic factor which must be considered -- regardless of the certainty of the foreign energy source -- is the outflow of U.S. dollars required to purchase these supplies. The NPC has projected that 1985 energy imports will cost the country between $18 and $26 billion as compared to $3.6 billion in 1970.

Financial Factors

The financial problem is two-fold. First, the industry must spend capital monies in the next 15 years at a much greater rate than heretofore. Secondly, attracting these sums from the financial markets will be in a large measure dependent on an adequate prospect of profitability.

Political Factors

From the foregoing it is concluded that the impact of uncertainties in crude oil supply arising from physical, economic and financial factors can be reduced by a program based on the workings of the free market. We probably have no choice since the United States will be bidding for these supplies against other nations and vital national security interests are involved.

Political factors contribute the greatest element of uncertainty, especially since many are not under our national control. The United States, Western Europe, Japan and other oil consuming entities in the Free World will become increasingly dependent on the supplies of Africa and the Middle East.

One political uncertainty arises in the relative stability of the young governments of Africa and the Middle East. Another element of uncertainty arises from the functioning of power blocs created by the governments of the USSR and the Peoples' Republic of China. Finally, we must continue to negotiate price with the supplying nations in circumstances where their perception of value could cause major disagreement at the negotiating table.

It is a world problem and, as a consequence, world price will be set not just by our own actions but by those actions of all consuming and producing countries. However, there are domestic political efforts which can be undertaken to improve the certainty of supply of crude oil to the Nation's refineries. They would provide incentives to investment in domestic energy supplies.

It is evident that oil industry costs in the forthcoming period will accelerate more rapidly than general price levels in the economy. This implies a dedication of a greater fraction of disposable income by the citizen in acquiring energy, be it gasoline, heating oil or electricity. Efforts by the U.S. Government to restrain prices for political reasons will adversely affect profit incentives in all sectors of the oil industry. Such disincentive to investment would later be manifested by shortages as demand grows. Artificial stimulation of investment by the government could then be expected to ensue, accompanied by a substantial increase in degree of regulation.

Such a process would lack stability and efficiency, and continuing problems and uncertainties in energy supply could be expected. It would appear that government action should be toward a free market, not away from it. Investments made where capital recovery is expected only over periods of 10 or 15 years depend importantly on the predictability of market forces and actions of government. The Federal Government could do much to assist stability in the supply of crude oil (hence, energy products) by adopting a National Energy Policy around which the country could rally.

CONSTRUCTION COSTS AND LIMITATIONS

In addition to such refinery expansion constraints as financing, siting and environmental problems, the increasing cost of construction has also contributed to the shortfall of refinery capacity. For instance, construction cost indices have risen over 50 percent during the decade of the 1960's.

Cost of construction is less in the Caribbean than in the Canadian Maritime Provinces and at most U.S. locations, except the Gulf and West Coasts. As an example, contractors active in many different areas offer the following cost factors for construction of similar facilities relative to the Gulf Coast:

Areas	Cost Factors
Canada, Maritime Provinces	1.2
Gulf Coast	1.0
Caribbean (Jamaica - Puerto Rico - Virgin Islands)	1.1
East Coast (Baltimore - Philadelphia)	1.15
Midwest (Chicago - Kansas City)	1.15
West Coast	1.0

Furthermore, more stringent environmental considerations in the United States and Canada for future construction will increase the cost per barrel of throughput relative to the costs at a Caribbean site.

Possibly the most significant factor in future construction costs is not the cost difference between locations, but the effect of the total workload on the construction industry. Since 1952, refining and chemical industry expenditures fluctuated around $3 billion until it peaked at nearly $6 billion around 1966-1967. Expenditures have been cyclic in nature and each peak period has been accompanied by signs of stress in the industry -- almost complete reliance on more costly "cost-plus" contractual arrangements, slow equipment deliveries, poor quality of work, labor shortages and pressures for overtime. Despite these problems, facilities were completed, although at a higher cost and on a delayed schedule.

Although the future is extremely difficult to predict, the need for increasing levels of investment in the refining industry alone is great. There will be a need for additional refinery capacity serving the United States of about 11 MB/CD between 1970 and 1985 which will require a total of as much as $23 billion -- or

$1.5 billion annually. This expansion investment, plus capital investments in the refining industry for product quality improvements, environmental obligations, and modernization for obsolescence or efficiency and probable increases in investment in the chemical industry, will tax or exceed the capacity of the "heavy" construction industry. Many in the petroleum industry have questioned the ability of the construction industry to meet these future expansion requirements with reasonable costs and minimum delays.

To understand the current capability of that portion of the construction industry associated with refining and chemical plants, three main factors have been examined separately. These are engineering contractors, material suppliers and fabricators, and construction labor.

Engineering Contractors

Engineering contractors have drastically reduced their forces since the peak years of the mid-1960's because of the slump in refining and chemical-type construction. Many of the engineers have moved to nonoil industry jobs. As a whole, however, contractors have been successful in retaining many of their key employees at all levels, and this cadre will serve as a building block for expansion. Hopefully, many of the contractors' former employees will return to the construction industry when the need arises. Furthermore, there is a pool of retrainable people formerly associated with the defense related industries. However, process engineers will remain the most critical discipline.

The Fluor Corporation in mid-1972 made a projection of the outlook for the U.S. engineering and construction market for the next 5 years (see Table 47). Although no attempt has been made to verify their projection for each category, their estimate for petroleum refining is reasonably consistent with the one put forth by this Committee. In any case, this table indicates the magnitude of technical manpower problems the construction industry will face in the future. This technical manpower may be slightly less than indicated -- to the extent that future refining projects are of larger scale, less engineering manpower per barrel per day of capacity will be necessary. Similarly, a greater than historical grassroots expansion results in a higher proportion of offsite facilities which require less engineering support. In any case, technical manpower will have to grow rapidly to undertake the expected flow of capital commitments.

Material Suppliers and Fabricators

A survey of 18 leading manufacturers and fabricators serving the refining and petrochemical industries was made in 1970 regarding growth of their productive capacity. On the average, they reported an annual growth in capacity of 8 percent during the 1965-1970 period. While limited activity in the past 2 or 3 years

TABLE 47

U.S. ENGINEERING AND CONSTRUCTION MARKET OUTLOOK – 1973-1977
(Capital Commitments – Millions of 1973 Dollars)

	Petrochemicals*	Petroleum Refining	Synthetic Natural Gas Liquids	Synthetic Natural Gas Coal	Synthetic† Crudes	Residuum Desulfurization	Miscellaneous‡	Total	Ave. Tech.§ Contd. Staff Required
1973	2,200	1,300	300	700	700	550	140	5,890	20,500‖
1974	2,500	1,350	500	350	400	500	500	6,100	25,200
1975	2,650	1,500	700	500	700	500	450	7,000	32,000
1976	2,900	1,600	700	700	400	350	800	7,450	36,900
1977	3,100	1,650	700	900	800	450	750	8,350	39,800
Total	13,350	7,400	2,900	3,150	3,000	2,350	2,640	34,790	
	(38.4%)	(21.3%)	(17.4%)		(8.6%)	(6.8%)	(7.6%)	(100%)	

* Excludes work by captive personnel.

† Includes liquids from tar sands, shale oil, and coal liquefaction.

‡ Includes gas treating, domestic and overseas liquefied natural gas (LNG) facilities, and foreign contracts.

§ Calculated at $190,000 in-place plant per technical man-year.

‖ U.S. technical manpower (major E & C) staff estimated at 18,000 on 1/1/73.

SOURCE: The Fluor Corporation, 1972.

may have forced them to develop other outlets for their capabilities, it is reasonable to assume that they can once again match and even exceed the capacity reached during 1966 to 1967.

Construction Labor

Construction labor is an enigma. The skills of and the numbers in the labor pool in a geographical area tend to be determined by the historical level and type of activity in that area. Today's craftsman is relatively immobile and he is not too interested in traveling to a distant job site just for the sake of employment. If he is mobile, he tends to migrate to the projects that are paying large amounts of overtime. Local labor leaders take varying attitudes toward accepting the worker who will travel and to allowing the local residents with some skills to work on a permit basis. Recent incentives to increase the size of the local labor organizations have been minimal because there has been some degree of unemployment in many areas. As a result of this, apprentice training has moved slowly. In fact, the level of apprentice training may not have been sufficient to replace attrition in some of the crafts. In areas where the numbers of craftsmen have increased, there is probably some form of long-term employment opportunity foreseen that will accommodate the increase.

In view of the above considerations, it is probable that the numbers of craftsmen readily available for refinery construction are not much greater, if any, than were available during the last industry construction peak. To duplicate the peak, one must anticipate the same pressures for overtime that existed before, productivity problems and additional leverage for higher compensation. Furthermore, this increased activity in the power generation field may have its greatest impact in the area of construction labor and thereby adversely affect the refining industry.

In summary, it would appear that the engineering contractors and the material suppliers and fabricators will be able to achieve or slightly exceed the peak activity demonstrated during the 1966-1967 period; however, it remains very uncertain that they can meet all the future construction needs. Construction labor will probably be limited, and relief will come only if labor accepts the challenge to open employment channels. Although the labor resource is the most questionable of the three areas, the availability of the technical manpower may also become limiting.

Outside Factors in Other Industries

Power Generation

The power generation industry started an expansion program in the late 1960's that has been setting new peaks. There is a need for expansion as witnessed by the actual or threatened brownouts in various parts of the country. In all probability, the peak expenditures have not yet occurred in this sector particularly if there is a significant move toward stack gas effluent control devices. Problems in obtaining permits and suitable sites have at least partially accounted for a backlog in the power generation industry and, thus, there is a contained demand that can break loose in the future.

For many of the same reasons, the power generation industry now is tending to locate their new facilities in the same general areas that are attractive to the refining industry. Thus, there is bound to be a conflict for construction labor in these areas. The impact of this development has yet to be assessed as the demand in the two industries has not yet peaked at the same time. Timing of the expansions in the same area will be critical.

Synthetic Natural Gas (SNG) and Liquefied Natural Gas (LNG)

There are a number of plants (both SNG and LNG) now being engineered and constructed. While the exact future of this industry is far from clear, pending further rulings by the Federal Power Commission (FPC), it can impact on refinery construction in several aspects -- construction engineering and labor and material fabricators, particularly those supplying rotating equipment such as compressors. Certainly there will be competition for the technical engineering staffs of the construction companies.

Just as with utilities, the locations tend to be near population centers, the same areas that are becoming increasingly attractive to refineries. Rapid expansion in this industry will compete directly for field manpower. Should the SNG and LNG industry become more significant, there will be direct competition with the refining industry in all aspects of construction. The end result might well be a sharing of the construction resources and a reduction in the capability to expand refineries.

Unconventional Raw Materials

As more emphasis is placed on developing unconventional sources for raw hydrocarbons, competition will develop in the contractors' shops and with the suppliers and fabricators of material and equipment. Since technology is still under development in this field, it is reasonable to assume that this competition will not develop until late in the decade and that it will first be noticed in the contractors' offices. At least insofar as needs through 1980 are concerned, the conflict should be minimal. Forced acceleration of a program to develop unconventional sources, however, could affect this judgment.

Conclusions

It may not be possible for the construction industry to meet all of the future demands of the refining industry without excessive costs and delays to the industry. Construction labor will probably be the limiting factor. Many of the problems associated with the peak years of 1966-1967 will again be encountered. Generally, expansion will tend to occur at or near the existing refineries. New sites in other labor markets would assist in solving the labor problem. Competition with the power generation industry will detract from establishing new refining centers near market concentrations.

Further delay of the expansion program will create the need for higher annual expenditures, historical investment opportunities may have to be set aside and environmental and incompleted lead removal projects may have to be deferred. Significant expenditures for product improvements or specification changes will present problems even under the normal expenditure schedule for expansion unless environmental expenditures are delayed. In the delayed expansion case, expenditures of this nature likely would be impractical.

REFINERY FUEL

The availability and cost of fuels have become recent problems which must be considered in building new refinery capacity in the United States. Whereas domestic refineries have enjoyed a very favorable climate in terms of fuel costs in the past, this situation is changing, and the outlook is toward substantially higher levels for the future. One effect of the significant increase in fuel cost expectations is a shift in the relative positions of such costs between domestic refinery and offshore refinery locations. In other words, the historic refinery fuel cost advantage of domestic locations, particularly on the Gulf Coast but also in other domestic areas, is expected to disappear and become an economic disadvantage *versus* offshore locations in terms of new refinery capacity.

There are several reasons for this marked change in outlook for fuel costs for new domestic refinery capacity. The principal factor is the future availability and value of natural gas. Although domestic refineries use significant volumes of fuel oil, refinery gases and petroleum coke for fuel, a high proportion of fuel requirements are met by external supply in the form of natural gas. In 1971, natural gas accounted for about 40 percent of the fuels consumed at domestic refineries nationally and almost 60 percent of such fuels consumed in PAD District III. Furthermore, other refinery fuel supplements have tended to be valued in relation to natural gas prices which, until recently, at Gulf Coast locations could be obtained at less than half the cost of domestic crude oil. Fuel costs in other domestic locations generally reflected the added transportation costs of gas and the competitive economics of alternate fuels.

Because of limited natural gas supplies, there is at present both an active gas curtailment program by suppliers, which is reducing the availability for refinery fuel, and also a trend toward higher alternate use values for natural gas from the historical low levels of the past. While refineries receive natural gas supplies from a variety of sources, such as from their own producing functions, from intrastate suppliers and from natural gas utilities, the possibility of obtaining natural gas for a large new or substantially expanded refinery appears dim for all locations. Such a shift in developments points toward total dependence upon refinery produced product for refinery fuel at substantially higher costs for these projects. The availability of low-cost natural gas for hydrogen and joint petrochemical operations, as well as the supply of related natural gas liquids feedstocks for both refining and petrochemicals, are integral parts of this problem.

At the same time that the outlook is changing radically for refinery fuel costs in terms of past dependence upon low-cost external natural gas supplies for new domestic projects, alternate fuel choices must be made on the basis of environmental improvements, both in refinery products produced for sale and those products produced for plant consumption. In particular respect to refinery fuels, sulfur specifications must be planned to meet emission standards which are being set forth by all the states. From an economic and alternate fuel standpoint, the net effect is a further rise in cost and the elimination of high-sulfur content supplies of fuel oil, coke and coal from consideration in new projects.

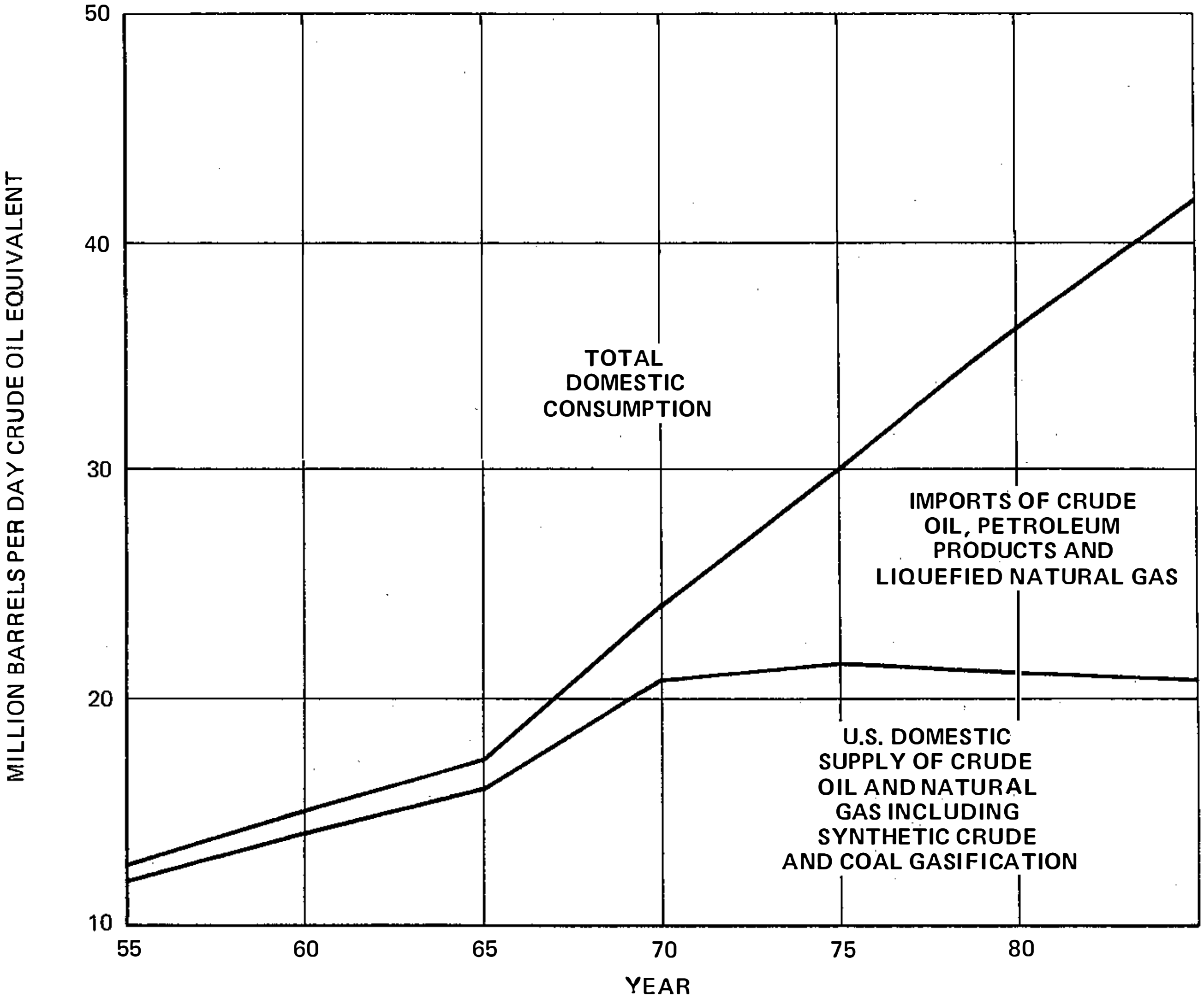
In contrast to new domestic refinery capacity, plants located offshore to supply petroleum markets in the United States must meet domestic product sale specifications but generally are permitted to burn fuel with a higher sulfur content. While most such locations do not have access to natural gas supplies and fuel and hydrogen are produced internally from oil, the absence of sulfur emission standards results in lower fuel costs than comparable new capacity fueled by oil at domestic locations.

In summary, the very favorable fuel cost climate enjoyed by the domestic refiner is in a process of change. Limited supplies and alternate value economics have entered the picture in the case of natural gas, and emission regulations have changed the outlook for alternate fuels by eliminating the consumption of high-sulfur content fuels. Thus, the domestic refiner is faced with an increase in fuel costs for new or expanded capacity from the historical level of less than half the cost of domestic crude oil to the equivalent of sweet crude costs or higher. Changes in the level of fuel value will also force a change in the value of lighter refined products (C_3, C_4, C_5) with alternate sales potential, tending to increase their sales price as an incentive for removal from refinery fuel. Although strong incentives exist to minimze heat requirements, such a large increase in fuel costs cannot be offset by gains in efficiency. These developments have introduced new problems into refinery construction planning, both in terms of higher domestic costs and in terms of the competitive economics of various locations.

PETROCHEMICAL FEEDSTOCKS

The primary effect of the "energy crisis" on the petrochemical industry will be a switch from natural gas liquids feedstock to heavy liquids feeds derived primarily from refining operations. Associated with this change in feedstock will be a significant increase in production of energy by-products by the petrochemical industry. Thus, close coordination of operations and planning between the refiner and petrochemical producer will be required in the future.

The huge capital investments that must be made in heavy liquid olefins units require that the industry seek new ways to share the risk of these ventures through creative contractual arrangements. For the past two years there has been much discussion on the impending "energy crisis" which the United States is facing. For the most part this "crisis" has been interpreted as an imbalance between domestic supply and demand of crude oil and natural gas with the inevitable effect of an increased dependence on imported oil and gas. Figure 21 is a typical analysis of the problem in this regard.



Source: NPC, *U.S. Energy Outlook: An Initial Appraisal 1971-1985,* Volume One (July 1971) p. 13.
Data are converted into million barrels per day of oil equivalent.

Figure 21. U.S. Domestic Oil and Gas Consumption and Supply.

Recently attention has begun to be focused on the changing structure of the industry as it moves to heavy liquids as feedstock for olefins manufacture. The purpose of the following section is to assess the effect of these two aspects of the energy crisis on the petrochemical industry during the 1970's.

Demand for Basic Petrochemicals

Olefins and aromatics are the basic petrochemicals on which the U.S. petrochemical industry is based. The demand for these basic petrochemcials is supported primarily by the demand for plastics and fibers which are projected to grow at a rate of 10 to 13 percent per year during the 1970's. Over 50 percent of all aromatics and olefins are consumed in these end uses.

Industry projections of the growth rate for the major basic petrochemicals vary from 7 to 9 percent per year.*†‡ As shown in Figure 22, the demand for these petrochemicals is projected to increase from 33 billion pounds in 1970 to as much as 80 billion pounds by 1980. Ethylene alone is projected to grow from 16 billion pounds to 33 to 40 billion pounds by 1980, an average increase of 7.5 percent to 9.5 percent per year.

Olefins Plant Feedstocks

At the current time, petrochemical feedstocks for the production of ethylene are largely ethane and propane recovered from natural gas processing (LPG's) and, to a lesser extent, from liquefied refining gas (LRG) operations. These materials, together with other refinery gases, account for over 80 percent of the current U.S. ethylene production.§¶ Future supplies of these LPG's and LRG's are sufficient to satisfy current demands and to provide for modest expansions of ethylene production capacity. However, as shown in Figure 23, projected supplies will be nowhere near sufficient to satisfy the projected growth in ethylene demand during the 1970's.

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* Reynolds, W.W., "The Elements of Decision for Investment in Basic Petrochemicals," 71st National AIChE Meeting, February 23, 1972, Dallas, Texas.

† Spitz, P.H., "Charting Future Ethylene Growth," 71st National AIChE Meeting, February 23, 1972, Dallas, Texas.

‡ Humble Oil and Refining Company, *Chemical and Engineering News*, March 8, 1971, p. 15.

§ Reynolds, *Ibid.*

¶ Burke, D.P., Plyant H., "Energy Crisis," *Chemical Week*, September 20, 1972, p. 39.

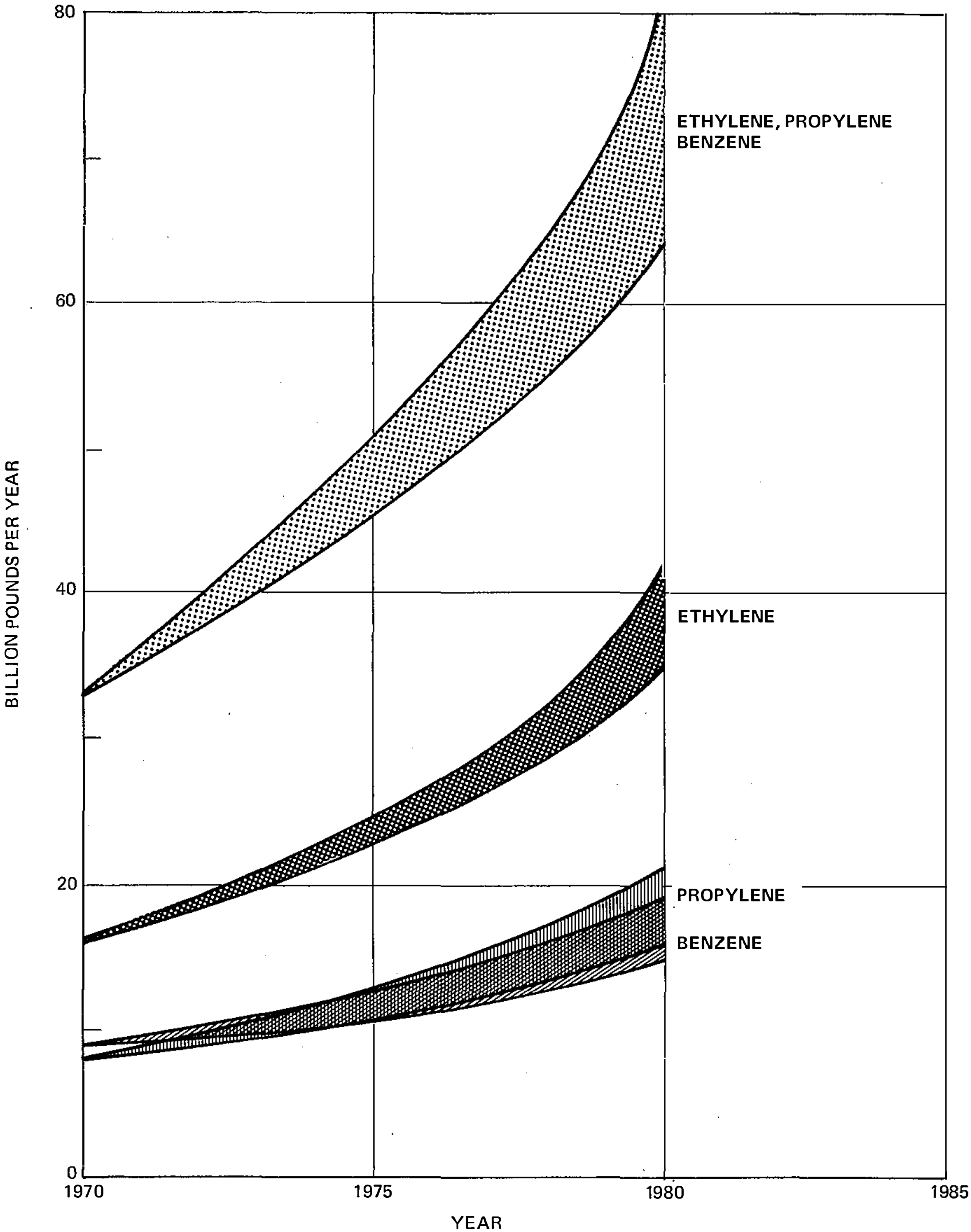
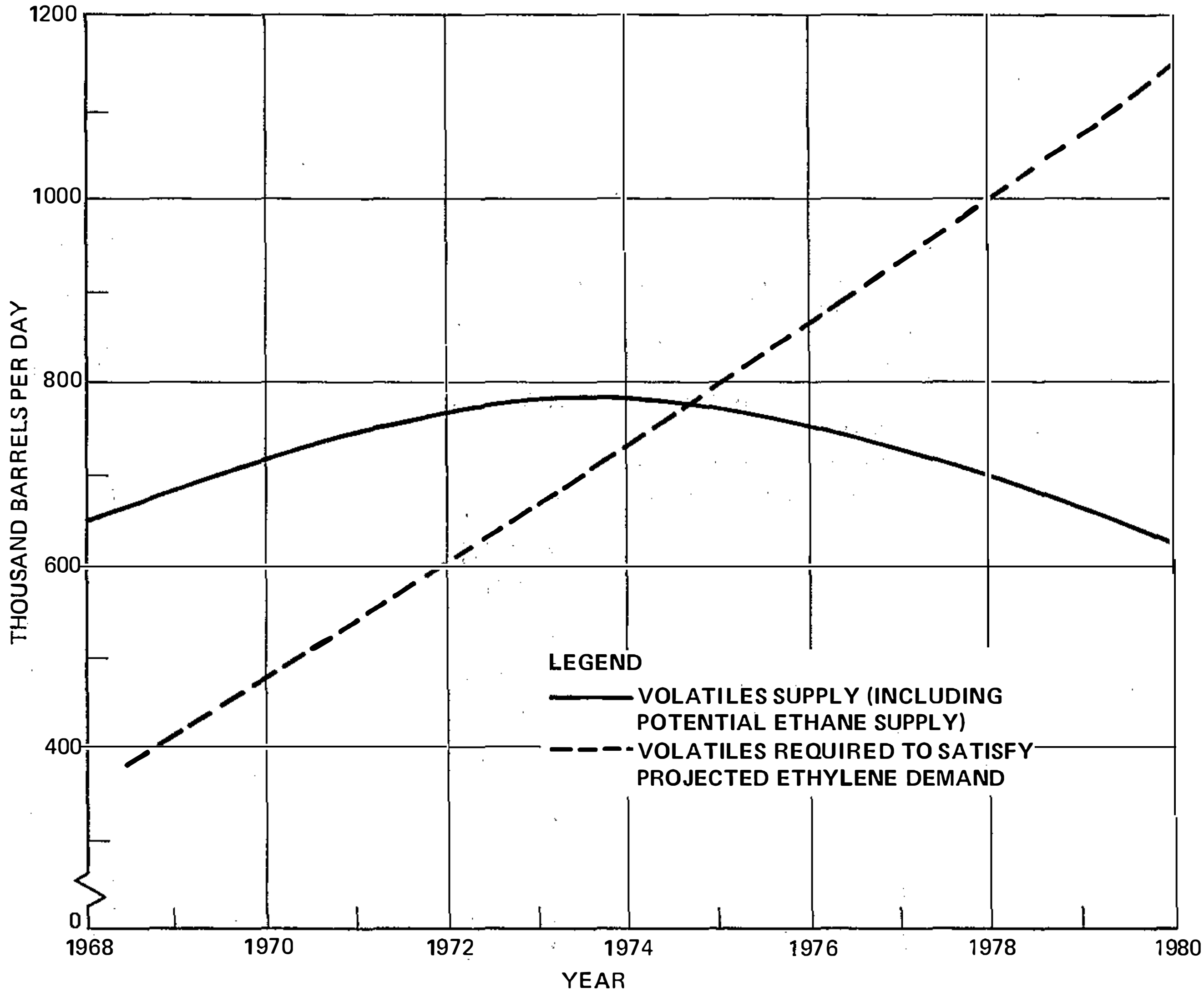


Figure 22. Basic Petrochemical Demand Projection.



Source: Shell Chemical Company

Figure 23. Domestic Supply of Volatiles for Chemical Use.

Furthermore, as natural gas prices increase, as they surely will in order to at least equilibrate with low-sulfur fuel values, ethane and propane values will rise accordingly. Price increases will be even greater if ethane and propane are used to enhance the heating value of low BTU synthetic natural gas (SNG) or as raw material for SNG production. For example, based on an SNG value of $1.25/MMBTU* ethane and propane would be valued at 8.7¢ per gallon and 11.5¢ per gallon, respectively for direct blending into low BTU SNG. As feedstock for SNG manufacture, the values could be as high as 7¢ per gallon and 9¢ per gallon, respectively. These values are considerably higher than late 1972 Gulf Coast prices of 3.0¢ to 3.5¢ per gallon and 5.5¢ to 6¢ per gallon for these materials.

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* This price seems to be a reasonable basis regarding production costs reported in the literature for proposed SNG plants: Algonquin SNG--$1.41/MSCF, Tecon--$1.23/MSCF, Columbia Gas--$1.12/MSCF.

Thus, as a result of the declining supply and increasing price of light hydrocarbons (see Figure 24), future expansions of olefins production will be based almost exclusively on heavy liquid feedstocks derived from refining operations (naphtha, gas oil) and from natural gas processing (natural gasoline, condensate).

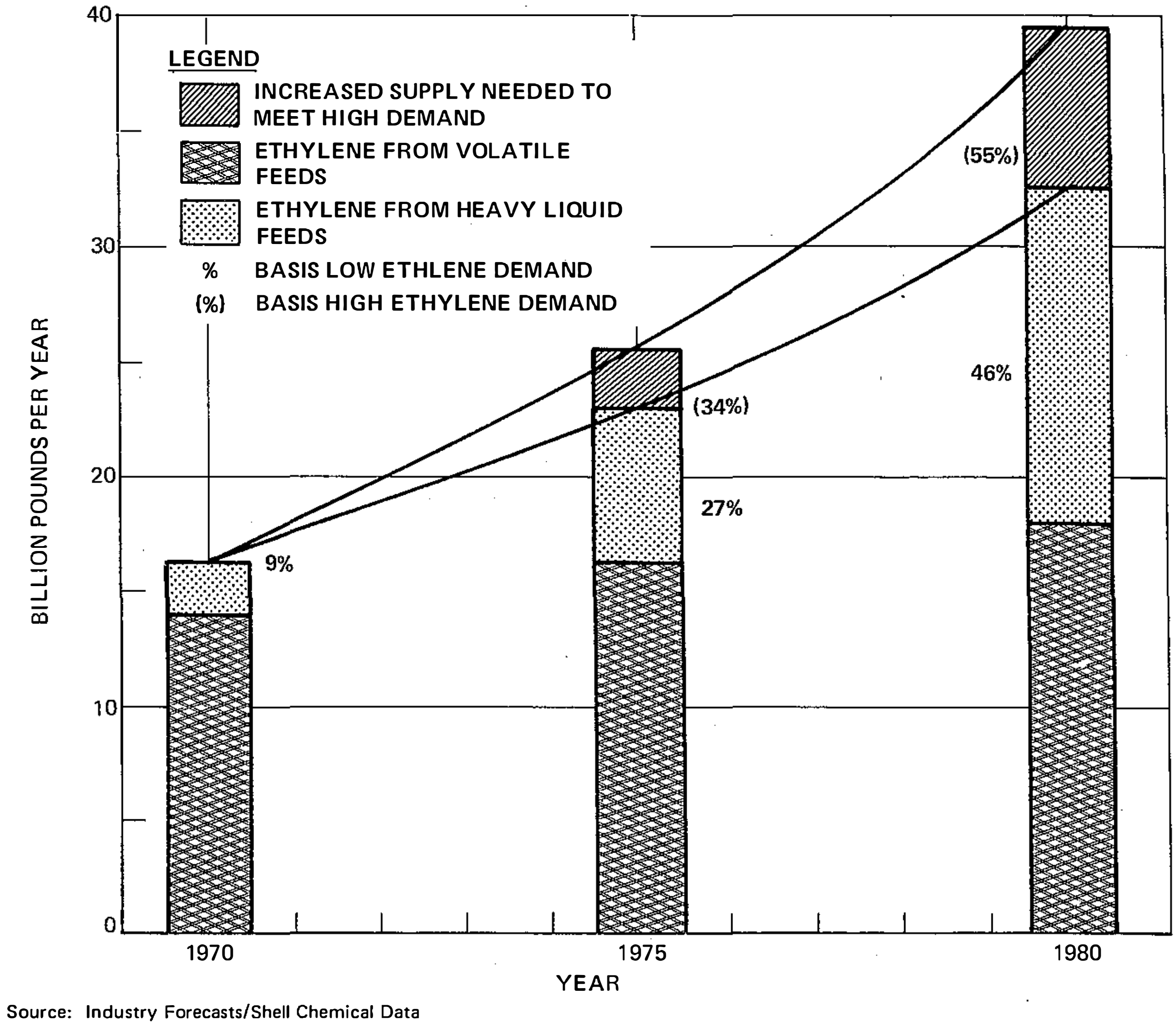

Figure 24. Projected Ethylene Demand.

Feedstock Demand

The total petrochemical feedstock demand (including demand for natural gas) is projected to increase at an annual rate of 6.2 percent during the 1970's. This will cause petrochemical feedstock demand to become a larger fraction of the total oil and gas consumption, increasing from 3.3 to 4.1 percent in 1980. However, the demands of the petrochemical industry will remain a very small fraction of the total domestic demand for crude oil and natural gas. Olefins plant feed requirements, reflecting the high demand for ethylene and the switch over to heavy liquid feedstocks, will increase at an annual rate of 13 percent on a gross basis. On a net basis the annual growth is 11.5 percent (see Figure 25). (Chem Systems have projected a growth rate of 11 percent per year on a gross basis.*)

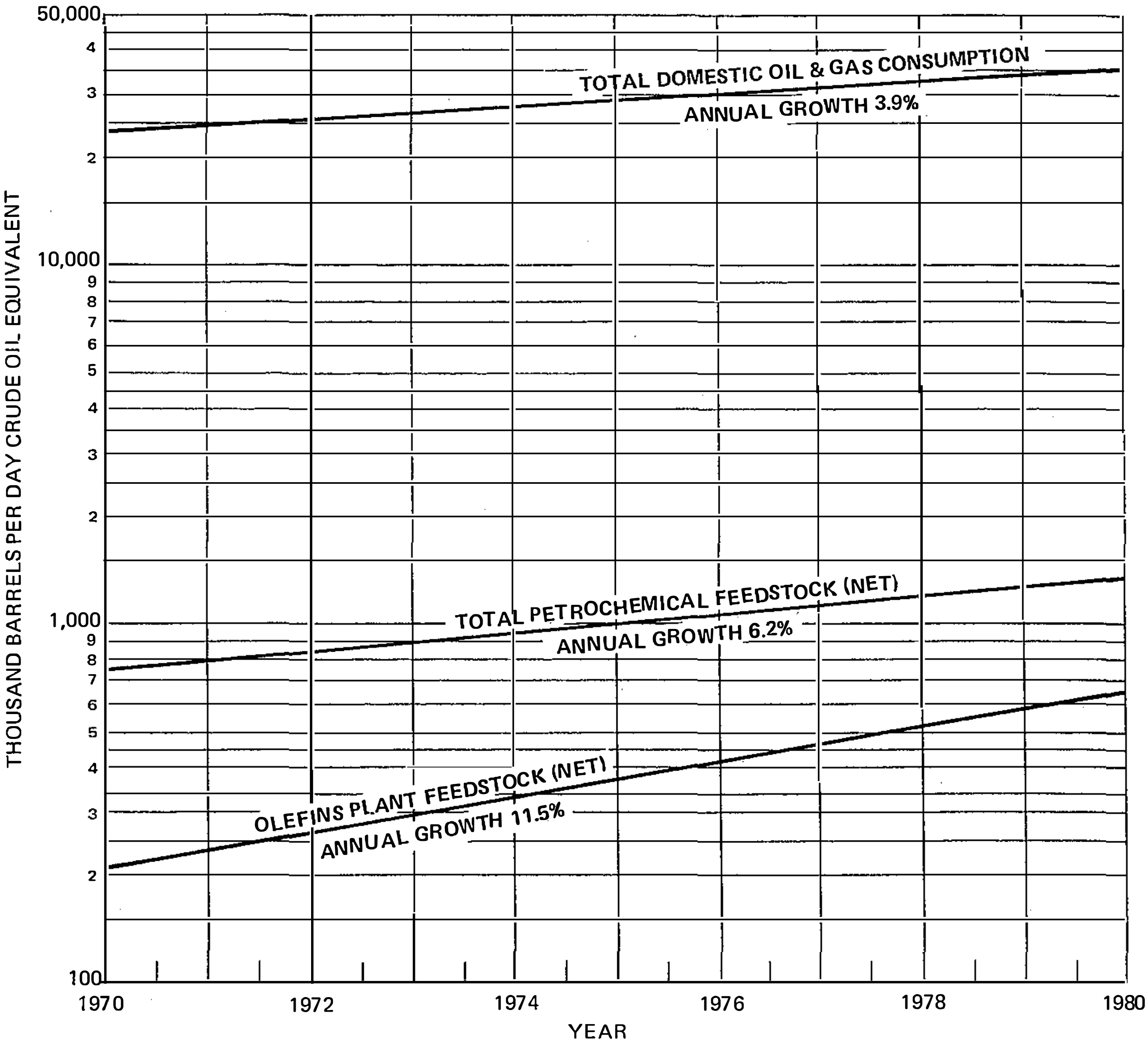

Figure 25. Annual Growth of Petrochemical and Olefins Plant Feedstock.

* Struth, B.W., "Economics of Olefins - 1980's," *Oil and Gas Journal*, August 2, 1971, p. 70.

During the same period domestic consumption of crude oil and natural gas is projected to grow at an annual rate of only 3.9 percent while total energy demand will increase at 4.9 percent per year.* A somewhat more conservative growth in energy demand (4.2 percent per year) has been projected by the National Petroleum Council.

Aromatics Production

The following shows that total demand for aromatics (benzene, toluene and xylenes) is projected to grow to 26 million pounds per year by 1980.†‡§

	1970 (MM Lbs./Yr.)	1980 (MM Lbs./Yr.)
Benzene	8.9	17.3
Toluene	1.0	1.9
Xylene	4.3	6.8
	14.2	26.0

This growth represents an average growth rate of 6.2 percent per year. More optimistic projections predicted an average growth rate of 7.8 percent per year.¶

At present, catalytic reforming is the predominant source of aromatics in the United States. Catalytic reforming accounts for more than 80 percent of the benzene produced and essentially all of the toluenes and xylenes. Currently about 13 percent of the aromatics in catalytic reformate are extracted for chemical use. Based on a conservative projection of catalytic reforming growth (5 percent per year) and assuming operating severity of 96 RON by 1980, aromatics available in catalytic reformate will increase to 23 MM gallons per year.** Chemical demand will reach 3.5 MM gallons per year or 15 percent of that available from reformate.

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* Shell Oil Company, "The National Energy Problem: Implications of Forecast Demand and Supply: Oil and Gas," May 1972.

† *Chemical and Engineering News, op. cit.*

‡ Clair, D.R., "Benzene Market Outlooks for '70's," 71st National AIChE Meeting, February 23, 1972, Dallas, Texas.

§ McCormick, W.A., Bonanni, V.A., "Xylenes--Supply/Demand Next Ten Years," 71st National AIChE Meeting, February 23, 1972, Dallas, Texas.

¶ Field, S., "What's Ahead for Aromatics," *Hydrocarbon Processing*, May 1970, pp. 113-120.

** *Ibid.*

In addition to aromatics available from catalytic reformate, large quantities will be available from pyrolysis gasoline streams produced from heavy liquid olefins plants. For example, a 1 MM pounds per year olefins plant processing a conventional gas oil feed, produces as much as 90 MM gallons per year of aromatics. Thus, by 1980 as much as 1.3 MM gallons per year of aromatics could be available from pyrolysis gasoline.

In view of the above, little change in the basic structure of the aromatics business is predicted. The bulk of aromatics demand for chemicals will be satisfied by extraction from catalytic reformate and aromatics prices will continue to be related to the value of aromatics in the gasoline pool.

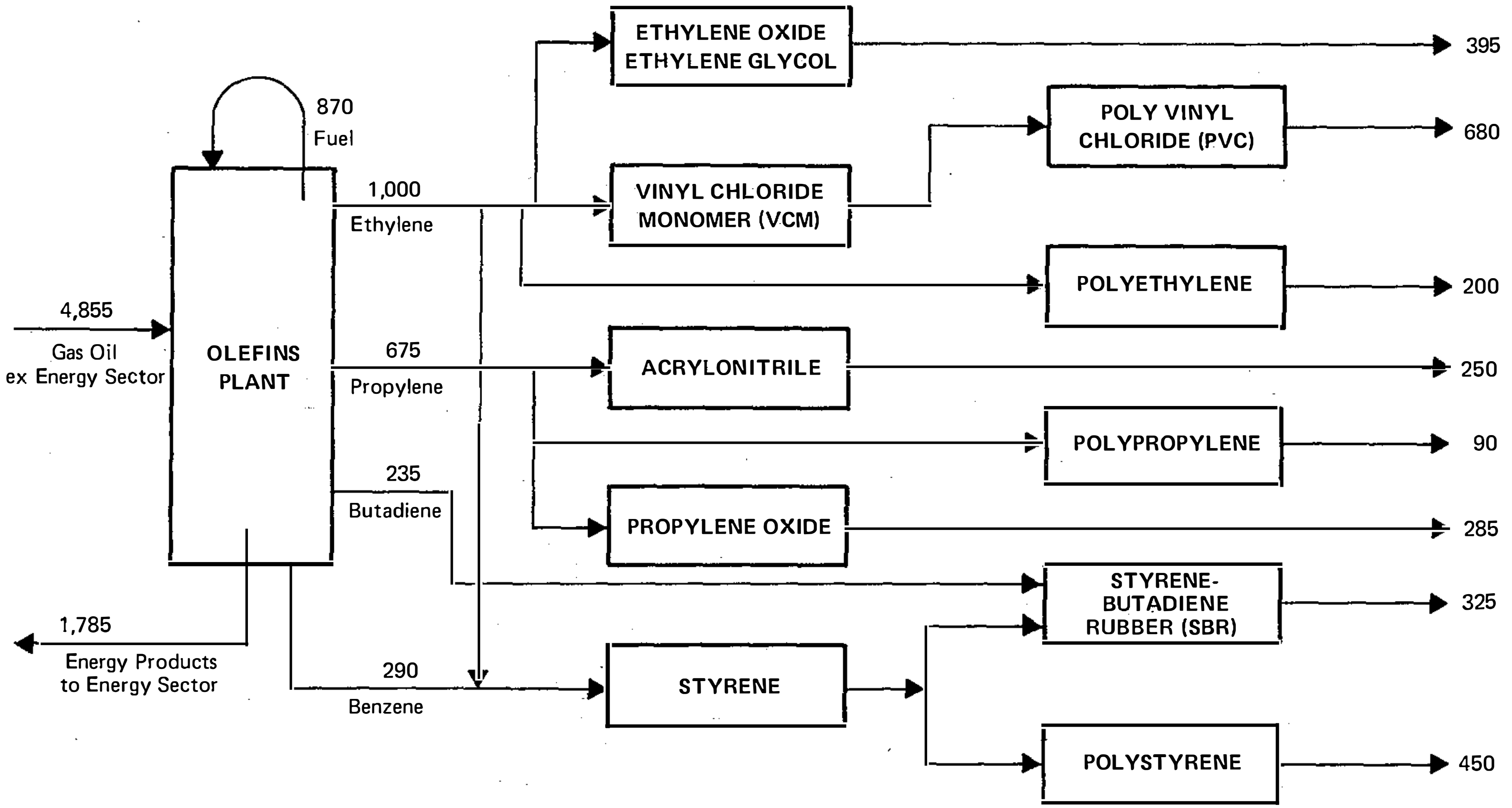
ECONOMIC FACTORS AFFECTING FEEDSTOCK SELECTION

The petrochemical industry in the United States has developed on the economic base of low-cost natural gas liquids as feedstocks for olefins manufacture. Yields of by-products which were consumed in the energy sector were minimal such that an investment in an ethylene plant represented a clear cut investment in basic petrochemicals. As the industry enters the heavy liquids era of the 1970's, this will no longer be the case. As shown in Figure 26, the product slate from a heavy liquid olefins plant contains a significant quantity of by-products which must be consumed by the energy sector. For example, energy by-products from a gas oil olefins plant, excluding offgas, represents about 37 percent of feed as compared with less than 3 percent for an ethane cracker. Furthermore, it requires nearly 5 billion pounds of heavy gas oil feedstock to produce 1 billion pounds per year of ethylene--over three times as much as when feeding ethane.

In addition to a significant yield of energy products, coproduct yields of basic petrochemicals from heavy liquids olefins plant are important. Total yield of propylene, butylene and butadiene from a heavy liquids plant is almost equivalent to ethylene production. Thus, no longer can the ethylene producer concern himself only with ethylene, but the marketing aspects of all the basic petrochemicals must be considered. His ability to profitably move these coproducts, as well as the energy products, will have a significant impact on overall project profitability.

Another factor which must be considered is the capital requirement for an olefins plant in the heavy liquids era. As shown in Table 48, the capital cost for a 1 billion pound olefins plant is almost $100 million for a naphtha unit as compared with $70 million for an ethane cracker. The cost of a gas oil cracker may reach $135 million.

Thus, the proper choice of feedstock for olefins manufacture in the future will not be obvious but will depend on the individual producer's circumstances. Such factors as relative feedstock prices (or values) and availability, values of various coproduct petrochemicals as well as energy by-products produced, and capital requirements for the facility must be considered.



	PRIMARY PETROCHEMICALS	INTERMEDIATES	POLYMERS	TOTAL
Gross Capital Investment Including Working Capital ($MM)	148	169	258	575
Revenue ($MM/YR)	115	158	229	502

NOTE: Flow Rates Expressed in Million Pounds per Year.

Figure 26. Typical Petrochemical Complex.

TABLE 48

OLEFINS PLANT CAPITAL REQUIREMENT
($MM)

	Feedstock			
	Ethane	Propane	Naphtha	Gas Oil
Total Capital	70	75	95	135
Capital Allocation				
Chemical Sector	69	71	71	97
Energy Sector	1	4	24	38

Basis: a) 1,000 MM Lb./Yr. Ethylene Production
b) Startup Date—1976

Advantages of Integration

As previously discussed, the shift to heavy liquid feedstocks will increase the relationship between the refining and the petrochemical industries. There is no doubt that maximum efficiency in the use of heavy liquids feedstocks will be realized by careful integration of petrochemical and refinery planning and operations.

This concept of the integrated petrochemical/refinery complex has received much discussion in the literature and at industry meetings. To the refiner, the integrated complex offers an attractive disposal alternative for low quality gasoline streams and the olefins plant serves as a partial conversion unit in that gas oil can be converted to highly aromatic gasoline and to olefins for potential alkylation feed. On the other hand, the complex provides the petrochemical producer with an assured feedstock supply and a convenient and attractive means for disposal of energy products from the olefins plant.

Another concept which has received much attention is that of a "chemical refinery" wherein crude oil is processed for the production of olefins and aromatics with no net production of energy products excepting residual fuel. This type facility, however, is not as attractive as the integrated petrochemical/refinery complex. Results of integration studies indicate that optimum petrochemicals production from an integrated complex is in the range of 30 to 70 percent of total product out-turn with a rapid decline in profitability outside this range.*

* Dutkiewice, B., "Integrate the HPI Interface," *Hydrocarbon Processing*, July, 1970, pp. 85-90.

Development of Petrochemical Complexes and Their Effect on the Industry

The economics of scale have caused significant increase in the size of the "efficient sized" olefins plant. In the early 1960's plants of 200 to 250 million pounds per year were built for a total cost of about $25 million. The standard size plant of today is 1 billion pounds a year costing from $100 to $135 million if heavy liquid feedstock is processed. The petrochemical out-turn from a plant of this size is sufficient to support several downstream derivative and polymer units. Since these basic petrochemicals, particularly ethylene, are difficult to transport long distances, petrochemical complexes will develop around the olefins plants in the future. An example of such a complex is provided in Figure 26. Such a complex will represent separate investments by several companies and will be connected to other complexes by relatively short pipelines, barge canals where appropriate, and railways.

A petrochemical complex of this type offers potential savings to the industry which will be passed on to the ultimate consumer. Location of suitable sites which will permit industry development along these lines must be found and approved if these savings are to be realized. The capital requirement for a typical complex will be about $500 million. Feedstock supply to the olefins plant, which produces the basic raw materials for the downstream consuming units, must be assured if the economic integrity of the complex is to be maintained. Thus, it will be necessary to develop means for effective coordination of operations and planning among the refiner, the olefins producer and the downstream derivatives and polymer. This type of coordination has not been necessary in the past since (1) the petrochemical industry developed from natural gas liquid feedstocks, which were in ample supply, and little, if any, coordination between the petroleum and chemical companies was required and (2) the olefins plants of the past were much smaller units and, hence, there were many fewer downstream units dependent on its out-turn so that close coordination of operating plants presented fewer problems.

Another barrier which must be overcome to permit effective coordination of the plans of the several business sectors involved in a petrochemical complex is that associated with supply contracts. Long-term (5+ years) contracts are written to assure physical supply and off-take in relatively thin markets. Escalator clauses or price schedules are written in to preserve the economic viability of each party's project. This places substantial stress on the ability to foretell general price movements in the economy. In spite of the uncertainties now faced by the industry, new ways for sharing the risk of these huge investments through creative contractual commitment must be devised.

Impact of Oil Import Regulations on Petrochemical Feedstocks

As discussed earlier, the U.S. petrochemical industry developed on the economic base of low-cost natural gas liquids for olefins manufacture. In the mid-1960's, it became apparent that supplies of natural gas liquids would soon be inadequate and that future growth of the petrochemical industry would necessitate a switch to heavy liquid feeds derived primarily from refining operations. However, the oil import control program precluded obtaining heavy liquid feeds except from domestic sources at costs higher than those existing in international markets. The petrochemical industry, therefore, sought an exemption from the Oil Import Regulations for importation of foreign naphtha petrochemical feedstock. Section 9B of the Oil Import Regulations, which was recently approved, granted this exemption for the importation of naphtha and other heavy liquid feeds. The impact that this will have on future feedstock selection is unknown.

The driving force which prompted the chemical industry to pursue this exemption was the historical differential of about 2¢ per gallon which has existed between the price of domestic naphtha and the delivered price of foreign naphtha. However, continued efforts by the OPEC Nations to escalate crude oil prices may ultimately approach equilibration of foreign and domestic crude oil prices. Should this equilibration be reached, the differential between imported and domestic naphtha prices will diminish.

Another factor to be considered in addition to price is availability. An estimate of Free World naphtha flows for 1970 was presented in a recent report of the Stanford Research Institute.* About 400 MB/CD of excess naphtha was available in the Caribbean in 1970 as a result of large scale production of fuel oil for the Eastern Seaboard of the United States. This naphtha, together with that from the Middle East, was utilized to balance naphtha demands of Europe and Japan. The amount of this Caribbean naphtha which could be bid away from other consumers at the much quoted "foreign naphtha" price is unknown, but it appears doubtful that a significant quantity could be obtained without a substantial price increase.

A factor which will affect both the price and the availability of foreign naphtha as petrochemical feedstock is the demand for this same material as SNG feedstock. Proposed SNG plants which have been announced to date could conceivably consume up to 750 MB/CD of naphtha by the mid to late 1970's.† In a paper presented at the meeting of the American Association of Chemical Engineers in Dallas in 1972, Union Carbide estimated that an attempt to import this volume of naptha would increase the delivered price by at least

* Stanford Research Institute, "Chemical and Petroleum Forecasting Program--Preliminary Report," March 1972.

† Importation of naphtha for SNG production is not currently permitted under current Oil Import Regulations. Issue is currently under investigation by the Office of Emergency Planning.

$0.50 per barrel and perhaps by more than $1.00 per barrel under more restrictive conditions.*

On the other hand, present government policy permitting the importation of heavy fuel oil and preferential tax incentives encourages the building of crude refinery capacity in offshore locations. Thus, the growth in naphtha supply is offshore. Until these imbalances are corrected and normal growth in domestic crude refining capacity is restored, it will be necessary to permit the domestic petrochemical industry to import naphtha feedstocks in order to maintain its normal growth. Otherwise, the petrochemical industry would also be exported.

In view of the above factors, and assuming the return to normal growth of crude refining capacity, the U.S. petrochemical industry will find it economically attractive on a long-term basis to utilize domestically produced raw materials to satisfy most, if not all, of their growth in feedstock demands. This conclusion supports the need for a strong domestic refining industry so that ample feedstocks will be available to the petrochemical industry at competitive costs.

Recent import/export balances of chemicals lend support to the foregoing. In the 1968-1972 period, imports of chemicals rose from $1.1 to $2.0 billion--an 82 percent increase--while exports rose from $3.3 to $4.1 billion--a 24 percent increase.† Imports have been increasing proportionately faster than exports, and the Nation's favorable trade balance on chemicals, which formerly enjoyed good growth, has shrunk in 1971 and 1972 from the peak level of $2.4 billion enjoyed in 1970.

FINANCING

Over the past 10 to 15 years the choice of location, either within or outside the United States, for construction of refining facilities by U.S. petroleum companies has not been influenced to any significant extent by differences in available financing. Although there was a period of about 2 years when money was extremely tight in the United States, this is not particularly relevant to the long-term trend in refinery construction under consideration.

For major international oil companies with strong credit records, adequate long-term financing is available in the Eastern Hemisphere for construction of refining capacity in that area at a cost equal to or slightly higher than the cost of money in the United States. Smaller companies with weaker credit ratings would

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* Dickinson, R.M., "Computer Analysis of Energy and Feedstock Values at the Petroleum--Petrochemical Interface," 71st National AIChE Meeting, February 23, 1972, Dallas, Texas.

† Eleven months actual, one month estimated.

pay more for long-term money in the United States, whereas in Europe they would have to rely on revolving bank credit or other short-term financing. In some cases, special government-backed financing may be negotiated, facilitating ease in obtaining construction capital.

The financing of refining installations in developing areas is somewhat different from that in Europe or the United States. Most developed nations (including the United States) have export promotion programs backed up by 8 to 10 year financing at interest rates somewhat lower than that which might be obtained from sources within the country in which the facility is to be installed. A major international oil company with a good credit rating would encounter borrowing costs very little different in an offshore venture than with a U.S. location, whereas a smaller firm with a short history of successful operation would generally find offshore financing slightly cheaper than raising money for a U.S. venture. The political stability of the host country is a factor which will be weighed heavily by financial lending institutions. Industrial development incentives plus U.S. crude import restrictions and other advantages, such as deep water close to shore, use of foreign flag vessels and a favorable tax climate, have made it attractive to construct a substantial amount of refining capacity in the Caribbean, basically to serve the U.S. East Coast heavy fuel market.

It may be concluded from the foregoing that the availability of financing at reasonable and competitive terms has not been a factor in choosing a European refining location *versus* a U.S. site, but lower interest rates plus the other factors mentioned, influenced some refiners in deciding to build in developing areas such as the Caribbean rather than in the United States. Implementation of regulations on foreign direct investment does not appear to have been a major deterrent to the construction of refining facilities outside the United States.

ENVIRONMENTAL CONSIDERATIONS

Environmental considerations will increase the costs of petroleum products in numerous ways. For example:

- Consumption of products will be increased by the substitution of low-sulfur fuel oil, LPG and distillate fuel for alternative high-sulfur petroleum, natural gas and nonpetroleum fuels (such as coal) and by use of less efficient automobile engines.

- Refining costs and crude oil requirements will be increased sharply in order to make environmentally acceptable fuels and to meet environmental standards.

- Transportation costs will be increased if refinery construction continues to be delayed or banned in the more economical locations.

- The magnitude of expenditures for environmental needs are significant as even large refineries (over 100 MB/CD) report costs in excess of 10 percent of all refinery investment to meet environmental regulations.

Estimates of expenditures to meet existing and proposed environmental regulations were obtained from the refining survey. Over the 6 year period 1973-1978, costs in terms of 1970 dollars are expected to total $3.2 billion for the 12.1 MMB/CD capacity covered by the survey response. This is equivalent to an expenditure of $265 per daily barrel of capacity, of which $110 will be required for manufacturing no lead gasoline, $54 for control of refinery water effluent, $90 for control of ambient air, and $11 for control of refinery noise and light. These environmental expenditures will be required over the next 6 years and are in addition to substantial expenditures already made by the industry. For perspective, this $3.2 billion expenditure is equivalent to the expenditures required to construct between 1.3 and 2.1 MMB/CD of additional refinery capacity, based on refinery construction costs of $1,500 to $2,500 per daily barrel of capacity. (For discussion of an illustrative case study, see Appendix H.)

Chapter Five

OIL IMPORT POLICY AND OTHER RELATED ISSUES OF GOVERNMENT POLICY*

INTRODUCTION

Government policies, legislation and regulations at the federal as well as state and local levels have become an increasingly more important factor to be considered in building and operating refineries in the United States. It is critical, therefore, that (1) existing policies and regulations be evaluated in terms of their impact on the shortfall of refining capacity; (2) current policies and regulations be modified as necessary to facilitate sufficient supply of imported crude oil and products to meet the short-term growth in demands; and (3) new policy guidelines be implemented within a reasonable period of time in order to maximize long-term domestic refining capabilities.

The decline in production of domestic crude oil and the near-term shortages in domestic refining capacity have been contributing factors in the emerging shortages of crude oil and products in the United States. Long-term planning by the oil industry to provide for increased domestic production of crude oil and adequate refining capacity for processing both domestic and foreign crude supply has become increasingly more difficult. Uncertainties and inconsistencies in government policies and the lack of consistent and cohesive long-term policy guidelines have aggravated the planning environment. Sound government policy guidelines at federal as well as state and local levels are necessary if the oil industry is to maximize supply for domestic sources.

The relative inflexibility of the crude oil quota system, coupled with the decline in domestic crude oil production, has

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** The President in his energy message to Congress of April 18, 1973, has removed by proclamation all existing tariffs on imported crude oil and products and has suspended direct control over the quantity of crude oil and refined products which can be imported. In place of the control system, the President has initiated a license fee system. The President stated that, to encourage domestic refinery construction, crude oil in amounts up to three-fourths of new refining capacity may be imported for a period of 5 years without being subject to any fees.*

This chapter was prepared prior to the issuance of the President's Energy Message and does not take into account or evaluate any of the policy changes or recommendations contained therein. The chapter does, however, evaluate various factors which affected refinery operations prior to April 18, 1973. Many of these factors are still relevant, particularly from the point of view of future governmental policy decisions, and are presented in that light.

restricted the development of new refining capacity. While it is true that total U.S. import quotas would increase by the amount of new capacity built, there has been no direct mechanism to provide an existing refiner or a potential refiner with the access to foreign crude oil supplies necessary to the operation of a new refinery in the United States. Limited and inadequate starter allocations were the only existing provisions for granting crude access for new refining capacity. The difficulities and costs of acquiring imported supplies from others were discouraging factors in decisions regarding new capacity construction.

OIL IMPORT POLICY--1954-1973

The principal element of government policies affecting the petroleum refining industry and the petrochemical industry has been the Oil Import Program. Voluntary and mandatory controls on the level of oil imports have now been in effect since early 1955. They have had a substantial and significant effect on the economies and logistics of the domestic refining industry.

Voluntary Import Control Program

The issues and concerns regarding oil imports actually predate World War II. Post-War policy, however, was effectively created by the establishment of the Cabinet Committee on Energy Supplies and Resources Policy in July of 1954. This committee concluded that in the interest of national security, imports of crude and residual oils should be kept in balance with the domestic production of crude oil at the proportionate relationships that existed in 1954. Importing companies were requested to limit imports on a voluntary, individual basis to conform with the policy directives of the Cabinet Committee. No effort was made to establish voluntary limitations by individual companies.

This phase of the voluntary system was reasonably successful until early 1957. By that time, tentative estimates of programmed imports by the oil companies indicated a significant increase in the level of imports. In response, the President established a Special Committee to Investigate Crude Oil Imports. After study of the facts, this committee concluded that the proposed level of imports in 1957 were a direct threat to the national security. It further recommended that unless importing companies comply with voluntary guidelines, the President should invoke the national security provisions of the Trade Agreements Extension Act.

Voluntary guidelines were more formalized as a result of the committee's recommendations. Controls were limited to crude oil imports, total levels of imports were developed by geographic area and individual company allocations were established. Because of the failure of certain companies to comply with provisions of the guidelines established in 1957, and because of the substantial increases in imports of unfinished oil and finished products, voluntary controls were eliminated in early 1959, and mandatory regulations were adopted.

Mandatory Oil Import Program

In order to minimize the shortcomings and difficulties experienced with voluntary controls, mandatory regulations were adopted, effective as of March 1959. The Mandatory Oil Import Program, like the voluntary control system, was adopted to restrict imports of petroleum to a level which would not threaten the national security and to provide a basis for preserving a vigorous and healthy petroleum industry in the United States. These restrictions and limitations on imports of petroleum were considered necessary to prevent a surplus of low-cost foreign production from displacing higher cost domestic supplies. It was evident that unless a reasonable limitation on imports was imposed, the following developments might occur:

- Oil imports would flow into this country in increasing quantities, entirely disproportionate to the quantities needed to supplement domestic supply.
- There would be a resultant discouragement of, and a decrease in, domestic production.
- There would be a substantial reduction in domestic exploration and development.
- In the event of a serious emergency, this Nation would find itself years away from attaining the level of petroleum production necessary to meet national security needs.

In suggesting mandatory controls in early 1959, the Special Committee to Investigate Crude Oil Imports further recommended that:

- Crude oil and its principal derivatives, including unfinished oils, be controlled.
- Bonded fuel imports be exempt from controls.
- Maximum level of imports of crude oil, unfinished oils and finished product (excluding residual fuel) in Districts I through IV (east of the Rockies) be limited to a fixed percentage of demand. (This was subsequently revised to a fixed percentage of production.)
- Maximum level of imports of crude oil, unfinished oils and finished product in District V be limited to the difference between domestic supply and total demand. (This was to recognize that District V was a deficit supply area lacking any significant inter-area flow of oil to meet the shortfall in domestic supply.)
- Imports of residual fuel be reviewed as necessary and adjustments made in the level of such imports consonant with the objectives of the program. (This was subsequently revised with controls on imports into District I effectively removed in 1966.)

- Imports of crude oil, unfinished oils and finished products into Puerto Rico should be limited to an amount which would not substantially exceed the level of imports during all or part of 1958, or to such levels required to meet increases or decreases in local or export demand. (This was subsequently revised to permit increased imports of feedstock and shipments to the U.S. mainland for facilities of benefit to the Puerto Rican economy.)

- Imports of crude and unfinished oil be limited to companies having refining capacity in the United States, and refinery inputs be used as a basis for allocations. (This was subsequently revised to include manufacturers of petrochemical derivatives.)

- Imports of unfinished oil be limited to 10 percent of an allocation. (This was subsequently revised to 15 percent in Districts I through IV and 25 percent in District V, with special provision up to 100 percent for petrochemical plants.)

- Import licenses be exchanged for domestic crude or unfinished oil providing that the domestic crude is processed in the importers' refinery.

- The Secretary of Interior be authorized to provide for the establishment and operation of an Appeals Board with the power to modify or grant allocations because of hardship, error or other relevant considerations.

The specific recommendations of the Special Committee to Investigate Crude Oil Imports were approved by the President and have remained the basic structure of implementing regulations for the Mandatory Oil Import Program.

This program has been in operation for more than 14 years. During this time period, it has maintained the total level of imports "controlled" within the framework of the President's proclamation and has provided procedures for allocating imports among eligible domestic companies. As the import program has evolved, the volume restrictions on certain imports have been removed. For purposes of this study, these imports are designated as "decontrolled." At the same time, certain procedures for distributing the quota for controlled imports have been revised in order to accommodate changing conditions and circumstances in the oil and petrochemical markets. Without elaborating in detail, the Mandatory Oil Import Program established:

- A system of quota-regulated imports in three separate geographic areas--east of the Rockies (Districts I through IV), West Coast (District V) including quota drawbacks for production of low-sulfur fuels, and Puerto Rico.

- A system of licenses for decontrolled imports of petroleum products from foreign refineries, principally residual fuel oil.

- An allocation system for distribution of quota licenses to petroleum refiners, petrochemical companies and, to a limited extent, marketers without raw material processing facilities.

- Preferential status for overland imports from Canada and Mexico in recognition of their proximity to the U.S. market and their inherent security advantages.

- Special exceptions for promoting and encouraging exports of petrochemicals and development of new industries in Puerto Rico, the Virgin Islands, etc.

Quota-Controlled Imports

Imports subject to quota limitations and allocations have been primarily limited to crude and unfinished oils requiring further processing in U.S. refineries and petrochemical plants. The allocation of licenses to refiners has been based on an applicant's refinery input prorated by a predetermined graduated scale for different levels of input. Basically, the sliding scale system provided smaller refiners a proportionately larger volume of import licenses relative to their eligible inputs than that of larger refiners. Quota allocations for the manufacture of petrochemical derivatives have been included in the quota system since the mid-1960's. The quota licenses for petrochemical feedstocks are allocated to both eligible petroleum refiners and chemical companies on a fixed percentage of plant input. The petrochemical import regulations for allocation of feedstock quota permit the licensee, with proper certification, to import up to 100 percent of such allocation in the form of unfinished oils. The import regulations permit the exchange of import licenses for domestic feedstock.

The total level of quota-controlled imports east of the Rockies is shown in Table 49. Until recently, this level was set at a fixed percentage of domestic crude and natural gas liquids production. Imports west of the Rockies (also shown in Table 49) have continually been derived as the difference between domestic supply and total demand. Overland imports from Canada, although not subject to formal quota allocation, have been included in the controlled level of imports in Table 49.

Crude and natural gas liquids production in Districts I through IV increased from 7.1 MMB/CD in 1960 to 10.0 MMB/CD in 1970. Since then, however, production has remained at about this level, averaging 9.8 MMB/CD in the first quarter of 1973. As a result, quota imports into Districts I through IV have increased substantially since 1970 in order to meet the growing shortfall in domestic supply. Quota controlled imports which were fixed at 12.2 percent of production have increased to almost 28 percent of estimated production in 1973.

TABLE 49

CONTROLLED IMPORTS
(MB/CD)

	1960	1970	1973*
		Districts I-IV†	
Finished Products	76	171	130
Crude and Unfinished Oil	776‡	1,138	2,600
Total	852	1,309	2,730
		District V†	
Finished Products	7	18	8
Crude and Unfinished Oil	292‡	464	942
Total	299	482	950

* As authorized April 1, 1973.

† Includes overland imports from Canada.

‡ Includes petroleum refiners and chemical companies.

Production in District V increased moderately from 1960 to 1970 (.9 MMB/CD to 1.3 MMB/CD). Since then, production has declined moderately (1.2 MMB/CD in 1972) thus accelerating the already existing deficits in domestic supply. As a result, quota controlled imports into District V have increased sharply.

Decontrolled Imports

Since 1966, imports of residual fuel oil on the East Coast (District I) have been exempt from formal quota limitations. Very little residual fuel is imported into the other districts and is generally subject to quota restrictions. The growth in residual fuel demand since the inception of the Mandatory Oil Import Program has been met entirely from offshore sources. Production of heavy fuel oil in U.S. refineries actually declined during this period.

The following have been excluded from quota restrictions: imports of liquefied petroleum gas from the Western Hemisphere, asphalt, overland imports of finished product from Canada processed from Canadian origin oil, No. 4 fuel oil imports and, more recently (the first 4 months of 1973), No. 2 fuel oil imports. In addition, a small but growing bonded fuel market has continually been exempt from import restrictions. This is fuel loaded in the United States on vessels and aircraft engaged in foreign commerce.

Imports formally exempt from quota restrictions increased from about .7 MMB/CD in 1960 to almost 2.5 MMB/CD in 1972. The increase of almost 2.0 MMB/CD has been primarily supplied from refining capacity located in areas adjacent to the U.S. mainland, and in effect represents refining capacity that might otherwise have been built in the United States. The ability of refiners to supply this market by processing lower cost foreign crude oil in areas adjacent to the U.S. East Coast has been the primary factor contributing to the export of refining capacity from the U.S. mainland.

This situation developed over many years and was primarily attributable to the underlying economics of fuel use patterns and the domestic refining industry. Foreign refiners with unlimited access to low-cost foreign crude could build relatively simple and less costly refineries to supply the heavy fuel oil market in the United States at costs competitive with gas and coal. Import policy recognized the prevailing economics affecting the manufacture of residual fuel oil in the United States and accordingly provided for liberal importation of foreign refined products.

Increasing requirements for naphtha to meet future petrochemical feedstock demands and potential requirements for manufacture of synthetic natural gas could result in accelerated building of new refining capacity in areas outside the U.S. mainland. The U.S. refiner, because of import regulations and economic considerations, is at a disadvantage in supplying the U.S. market with these products. Until recently, the economics of the domestic refining industry necessitated minimizing the yield of lower value heavy fuel oils. The increased demands for higher value, low-sulfur fuel oil has modified domestic comparative product economics to some extent.

Oil Policy Considerations

Import controls alone have not achieved the desired levels of exploration for new oil and gas reserves in the United States over the last 10 to 15 years. Mandatory controls, however, have maintained domestic production at levels which otherwise would have been substantially lower than the maximum production rates now being realized. Furthermore, in the absence of such controls it is reasonable to conclude that: (1) production in certain major fields would have been shut in with a significant loss potential; (2) most, if not all, of stripper well production would have been permanently shut off; (3) the decline in exploration activity would have been substantially greater; (4) exploration in the North Slope Alaska might have been delayed indefinitely; and (5) substantially more refining capacity to supply the U.S. market might have been built in foreign locations.

Although new reserves of oil and gas have not developed as originally anticipated and, in fact, have failed to keep pace with consumer requirements, the Mandatory Oil Import Program has nevertheless been instrumental in balancing the priorities of the domestic oil industry relative to oil imports from various producing areas. It should be recognized, however, that the circumstances and conditions leading to the adoption of formal quota controls in 1959 have changed considerably. Specifically, these were:

- A substantial surplus of oil production capacity existed in Districts I through IV during the mid-1950's.

- A worldwide over-supply situation prevailed.

- Excessive quantities of low priced oils from foreign producing areas were available for the U.S. market.

These circumstances led the Director of the Office of Civil Defense to conclude, in a special study on imports in February 1959, that:

> In such a situation, without control of production in relation to demand by the countries of origin, it is to be expected that there would be substantial economic incentives to increase imports into the United States.

The circumstances prevailing when formal controls were first adopted in early 1959 are in sharp contrast to conditions now existing, namely:

- That the domestic oil industry has moved from a period of "surplus" productive capacity (Districts I through IV) to a period of developing shortages of crude oil as well as refined products. Production peaked at a daily rate of 11.7 MMB/CD in the fourth quarter of 1970 and is currently averaging about 11 MMB/CD. Shortages of heating oils as well as some local shortages of jet fuel were evident during 1972. Shortages in domestic supply of gasoline have become a reality in 1973.

- The surplus of foreign productive capacity has been reduced significantly with developing shortages of low-sulfur crudes. Several countries have cut back production presumably as a "conservation" measure designed to maximize long-term recovery of in-ground reserves.

- The landed price of foreign crude oil and products has increased and, in some cases, now exceeds the price of equivalent domestic petroleum.

- The ownership of petroleum reserves in foreign producing areas is reverting to the host country governments.

In evaluating the impact of these changing circumstances on oil import policy and the import control system, it is quite evident that other policy considerations should complement the oil import control system as a means for developing an economic climate favorable to long-term development of domestic productive capacities as well as refining capacity. These considerations include but are not limited to the following:

- Recognition by the Federal Government that petroleum prices in the United States must be adequate to provide sufficient return on the new investments necessary to develop domestic resources. Flexibility for prices to adjust, based on market supply and demand within the United States, should provide sufficient incentive to develop a relevant degree of self-sufficiency in raw material supply and processing capabilities.

- The need to re-evaluate certain aspects of environmental regulations in order to ensure that benefits are commensurate with cost.

- The need to establish standards for orderly siting of new energy producing facilities in order to prevent the serious delays now realized in almost all facets of the energy industries.

The basic structure and implementing regulations governing the Mandatory Oil Import Program were adequate to meet the needs and conditions existing in the domestic oil markets for most of the time period since controls were first adopted. Events over the last several years, however, suggest that import policies and the import program will have to be modified to meet the needs of the immediate future as well as long-term policy goals.

The Mandatory Oil Import Program encouraged additional domestic crude production, which in turn supported an attendant amount of U.S. refining capacity. Placing limits on the volume of crude imports actually encouraged domestic refining capacity--as long as the import allocations were sufficient in conjunction with domestic crude production to meet total crude demands. However, there are certain aspects of the Mandatory Oil Import Program that created a negative influence on domestic refining capacity.

Imports of Unfinished Products

A percentage of the licenses allocated to refiners and petrochemical plants may be used to import unfinished products instead of crude. These percentages are 15 percent of offshore licenses awarded to refiners in PAD Districts I through IV and 25 percent for District V refiners. Up to 100 percent of the Canadian quota awarded to Districts I through IV refiners and, under special circumstances, up to 100 percent of awards to petrochemical plants may also be used to import unfinished products.

In the past, well over helf of the option to import unfinished products in lieu of crude has been exercised. By importing these unfinished products, which are usually components from crude distillation, less distillation capacity has been required in the United States. However, at the same time, downstream refining capacity has been provided in the United States to process the unfinished oils.

Imports of Finished Products

Provisions existed in the Mandatory Oil Import Program to permit finished product imports. In some cases, such as residual fuel oil imported into District I, no rigid control was exercised over the volume of products imported. In other cases, the product volume was limited and special product quotas were allocated in a variety of ways, such as awards to certain Puerto Rican refiners.

Petroleum products are refined in the United States from a combination of foreign and domestic crudes. Until recently, domestic crude has been higher in price than foreign crude. Therefore, products from U.S. refiners were higher in cost and price than products manufactured in foreign refineries from foreign crude alone. In addition to raw material cost differences, foreign refineries, in many cases, have been cheaper to construct and operate. This has further lowered the cost of products from foreign refineries relative to those produced in U.S. locations.

Thus, a driving economic force has existed to use all of the licenses granted to import finished products from foreign crude run in refineries located outside the United States. There has been a corresponding reduction in refining capacity required within the United States. For example, some of the finished product quotas apply to imports from the Virgin Islands and Puerto Rico, resulting in location of refining capacity there as opposed to PAD Districts I through IV.

Special Incentive Plans

In the past, certain plans have been considered to neutralize the raw material cost disadvantage that the domestic refiner used to face when foreign crudes were cheaper than domestic. These plans were designed to grant the domestic refiner treatment under the Mandatory Oil Import Program similar to that afforded to the offshore refiner.

For example, the foreign trade zone plan allows a refiner to build facilities on U.S. soil; however, his refinery is treated as being outside of the U.S. customs territory. The refiner is permitted to import crude outside of normal U.S. quota restrictions into the trade zone. The products manufactured in the trade zone are in turn subject to the same imports treatment as offshore products. However, establishing a foreign trade zone entails legal complications and requires strict segregation of the trade zone facilities from normal refining operations. As a result, the benefits of facilities integration cannot be realized.

There were other incentive plans that existed in the Mandatory Oil Import Program. For example, the low-sulfur bonus plan allocated crude quota to a PAD District V refiner equivalent in volume to his sales of low-sulfur fuel oil. The petrochemical import-for-export plan allocated quota based on the hydrocarbon contained in exported petrochemicals. The fuel oil desulfurization plan, which was suspended, would have in essence allowed the desulfurization of high-sulfur fuel oil imported without the use of regular unfinished quota.

These plans would have allowed the refiner to manufacture specific products (low-sulfur fuel oil in District V, exported petrochemicals, etc.) from foreign raw materials, just as the offshore refiner does. In this way, the domestic refiner would have been able to reflect the historically lower cost of foreign raw materials in the price charged for these specific products and would have been more able to compete with the products of foreign refineries. This applied to both exports of products from the United States and reduction of product imports into the United States.

Overland Crude Imports

Generally speaking, if overland crude imports were not permitted, they would be replaced by increased imports of offshore crude. Thus, permitting overland crude imports in the absence of other factors has a minimal effect on the volume of U.S. refining capacity.

In the case of Canadian crude imports, however, other considerations come into play. Products could be imported free of volume restrictions overland from Canada into the United States, providing the products were manufactured from Canadian crude in Canadian refineries. At the same time, the volume of Canadian crude and equivalent that may be imported is limited by Canadian export controls. This creates a driving force to locate refining capacity in Canada.

Quota Allocations

The majority of the import quota was allocated to refiners on the basis of their refinery throughputs. Those refiners wishing to process foreign crude must trade with other parties whose allocations exceed their needs. Under the allocation system, offshore import quota was distributed on a sliding scale basis which awarded a decreasing percentage of import quota as a refiner's throughput increased. Thus, the incentive to expand capacity resulting from quota allocations decreased with the refiner's size, thereby penalizing the construction of large, efficient refineries. This feature of the program discouraged U.S. refining capacity.

If quota grants had been equally prorated on the basis of throughput, a refiner would have received the same amount of quota for his first and last increments of throughput. In this way, increases in refinery runs would have earned more quota than under today's system, thereby lending more encouragement to expand domestic refining capacity.

Oil Import Policy and Refining Capacity

At present, the petroleum industry is operating near or at a maximum refining capacity in the United States, with every indication that persistent shortages of domestic capacity will exist for at least the next several years. The lag in development of new refining capacity in the United States, coupled with the extent of related capacity already exported to the Caribbean and other adjacent areas, is cause for serious concern. These trends involve a number of complex national as well as international considerations, the more important of which are discussed in the following sections.

The National Security

In evaluating the relationship of oil imports to requirements of national security, the Trade Expansion Act of 1962 (Sec. 232, Safeguarding National Security) provides that the President and the Office of Emergency Preparedness shall give consideration to:

> ...domestic production need for projected national defense requirements, the capacity of domestic industries to meet such requirements, existing and anticipated availabilities of the human resources, products, raw materials, and other supplies and services essential to the national defense, the requirements of growth of such industries and such supplies and services including the investment, exploration and development necessary to assure such growth, and the importation of goods in terms of their quantities, availabilities, character, and use as those affect such industries and the capacity of the United States to meet national security requirements.
>
> ...further recognize the close relation of the economic welfare of the Nation to our national security, and shall take into consideration the impact of foreign competition on the economic welfare of individual domestic industries; and any substantial unemployment, decrease in revenues of government, loss of skills or investment, or other serious effects resulting from the displacement of any domestic products by excessive imports shall be considered, without excluding other factors, in determining whether such weakening of our internal economy may impair the national security.

An expanding, viable domestic refining industry capable of meeting primary product demands is essential to the economic structure of the U.S. oil industry and the considered requirements of national security. Although the U.S. oil industry will require substantially larger volumes of foreign oil to supply the anticipated growth in demands, maximizing domestic refining capacity to the fullest extent possible provides a greater degree of flexibility in meeting basic national security considerations. To increase product imports at the expense of domestic refining capacity would place the United States in a position of having to depend on foreign sources for not only a growing part of its crude supply but also to an increasing degree on foreign processing capacity. This would appear contrary to the national security and the national defense as defined by Section 232 of the Trade Expansion Act.

In February of 1970, the Cabinet Task Force on Oil Import Controls concluded that:

- National security in petroleum requires that there be sufficient domestic refining to meet essential U.S. demand in supply emergency.
- Sufficient capacity requires not only adequate "barrels per day" capacity but also the ability to accept different types of crude inputs and produce different outputs in response to a supply crisis.
- Any system of import restrictions should be designed to maintain adequate refining capacity and flexibility, to encourage maximum competition and to safeguard existing investment to the greatest extent possible.

The Political and Economic Risk of Foreign Investment

One of the more critical issues to be considered in evaluating onshore *versus* offshore location of refining capacity to meet domestic requirements is the uncertainty created by political and economic instability in various areas of the Free World. The growing rate of expropriation and nationalization of American and other foreign investments in such areas must be considered in determining the advantages and disadvantages of import policies which would substantially increase product supply from foreign refiners. Foreign refineries, designed to export the majority of their output, are located either in proximity to crude oil resources or along transportation routes between major sources of crude oil and the major markets, and are potentially more vulnerable to the risk of political and economic pressures than are market located refineries.

Short of actual expropriation and/or nationalization is the risk of host government control of part or all of the operations of a particular facility. This could affect a company's operations in any number of ways including the availability of supply, price and, possibly, control of finished product sales in consuming areas. These are risks which must be weighed in evaluating the long-term security of such facilities.

Foreign Host Country Demands

Notwithstanding the political and economic risks involved in the export of refining capacity to supply the U.S. market, there is the real possibility that, in the long run, the U.S. Government may not be in a position to effectively implement policies designed to maximize construction of refining capacity in the United States.

Oil producing country members represented by the Organization of Petroleum Exporting Countries (OPEC) have about 80 percent of the non-Communist world's oil reserves (see Table 14, Chapter Two) and supply almost 85 percent of Western Europe's and Japan's oil requirements. An increasing percentage of U.S. requirements is expected to be met from production from these sources through at least 1985.

The investments and operating interests of U.S. nationals in these foreign producing operations are huge. The economic return from such operations has for some time represented a strong and favorable element in this country's balance of payments. In these circumstances, the U.S. Government should continue equitable tax treatment of U.S. investments abroad, including U.S. income tax credits for foreign income taxes paid.

Further, these foreign interests of U.S. nationals are deserving of full understanding and positive support of the U.S. Government. Particularly important is the need for the U.S. Government to continue to advocate the free flow of capital and technology to oil producing countries with the understanding that U.S. private investments will be equitably treated on the basis of commitments made by both the host country and the U.S. investor. Of course, the legitimate demands and concerns of host countries deserve and should receive serious and full consideration by the U.S. Government.

Early in 1972, a number of oil companies agreed in principle to the OPEC request for 20 percent participation in exploration and producing operations. Subsequently, Kuwait, Qatar, Abu Dhabi and Saudi Arabia agreed to acquire an initial 25 percent interest in operations within their respective countries and an eventual 51 percent interest by 1983. Negotiations are now under way, or remain to be completed, with a number of other foreign producing country governments, including Libya and Nigeria.

The whole matter of foreign producing governments participating in downstream operations remains highly uncertain. With so many important matters still to be negotiated with respect to exploration and producing operations, it would be premature to speculate too much at this time on the extent and method of such participation. Nevertheless, the agreements already negotiated with foreign producing countries have raised the possibilities of future participation by these producing countries in the downstream refinery operations of the oil industry. The extent to which this may materialize in the construction of new capacity in either the consuming markets or producing areas could have far-reaching significance on long-term import policies.

The concept of "participation" is not new or unique. Joint ventures in which private companies operate in conjunction with national concerns have been in effect for some time in a number of areas. Hopefully, producing country government ownership or participation in foreign oil operations will work to strengthen existing relationships between oil companies and foreign governments and thereby contribute needed stability to these operations as well as moderate widely different current political attitudes.

Over the longer term it seems inevitable that the higher the cost of oil from the OPEC countries rises due to increased government "take," the greater the incentive will become to explore for and develop crude oil reserves or synthetic oil from coal or shale in the United States. Also demands for participation, with 51 percent control by the host governments, improve the relative attractiveness of investing in domestic producing and refining operations. A constructive policy to encourage development of domestic energy sources is clearly called for. U.S. oil imports will rise in any event due to limitations in domestic supply, but the greater the encouragement of domestic oil resources, the less the growth in imports will have to be.

Recognition of these foregoing considerations may result in major changes which affect traditional positions, but on the other hand, they will provide opportunities for establishing policies consistent with the political and economic factors of today and the future. Thus, neither a rigidly defensive posture on one side, nor an irresponsible radicalism on the other, can help to create a balanced and more stable situation in which the legitimate goals, requirements and interests of the oil exporting and importing countires, as well as of the international oil companies, can be reconciled and realized.

U.S. Government policy may be forced to recognize the growing level of hydrocarbon imports as but one part of the total energy supply required to meet rapidly expanding domestic requirements--taking into consideration national security, foreign policy and technological, economic and environmental factors. As the U.S. becomes more dependent on petroleum imports, increased refining capacity could give the U.S. more leverage in dealing with foreign producing countries. On the other hand, participation negotiations might ultimately lead to insistence by the foreign producing countries that some part of our imports be supplied in the form of finished products.

Balance of Trade

The National Petroleum Council's U.S. Energy Outlook Report concluded that oil imports could increase from 3.4 MMB/CD in 1970 to as much as 19 MMB/CD in 1985 (Case IV). The more likely level ranged from a low of 8.7 MMB/CD (Case II) to 13.5 MMB/CD (Case III). The NPC study further concluded that the annual deficit in balance of trade in petroleum fuels could increase to as much as $30 billion by 1985, with the intermediate range estimated at $13 to $20 billion. These conclusions were based on the following assumptions:

- No restriction on construction of refining capacity in the United States will be imposed.

- Future mix of imports will remain at present levels (47 percent crude oil, 40 percent residual fuel and 13 percent other products).

- Landed value of oil in 1985 will reflect projected 1975 crude oil prices based on escalation factors in Teheran and Tripoli agreements as follows:

Crude Oil	$3.73
Residual Fuel	4.34
Other Products	5.00
Weighted Average	$4.14

  This results in a very conservative estimate of 1985 prices and U.S. dollar outflow for imports.

- Transportation charges will remain constant at current levels.

- Deficits in the balance of petroleum trade of potentially as much as $30 billion annually will have serious consequences on the Nation's overall balance of payments by 1985. (All calculations used constant 1970 dollars.) The outflow of dollars in payment for oil imports has in the past been more than offset by an inflow of funds from the foreign operations of American petroleum companies (i.e., repatriated earnings and exports of related technology and equipment). It is unlikely, however, that increases in the dollar outflow of the magnitude indicated above could be offset by a corresponding inflow of earnings.

Importing proportionately more refined product by exporting U.S. refinery capacity for whatever reason would further impair the already unfavorable balance of trade projected in the NPC studies. The delivered price of imported crude oil is considerably lower than the delivered price of equivalent imported finished product. The annual dollar outflow on petroleum imports could be $2 to $4 billion higher if total imports in 1985 were limited entirely to other finished product. These estimates developed by the NPC are summarized below:

	Value of 1985 Imports (Billions of Dollars)	
	Case II	Case III
All Crude	11.8	18.3
All Finished Products	15.9	24.6
Current Mix	13.1	20.4

No allowance has been made for the impact of additional capital outflow to finance the incremental foreign capacity. The U.S. Government presently restricts capital outflows for foreign investment. An individual company's permissible outflow is determined by a formula which takes into account such factors as previous investment outflows during the 1965-1966 base period and the level of foreign earnings. Because of these restrictions on capital outflows, some U.S. oil companies have had to raise funds abroad in order to help finance foreign direct investment. Assuming that this situation remains unchanged in coming years, the construction of new refineries overseas to supply additional product imports into the United States would have to be financed largely abroad, with no additional capital outflows beyond U.S. Government limits.

Employment in the United States

The Department of the Interior indicated in a recent study that the "export" of refining capacity since 1961 has eliminated employment opportunities in the United States, not only in refining but also in other allied and supporting industries.* The study by the Department of the Interior indicates that more than 100,000 jobs may have been lost as a result of the increase in product imports of almost 2 MMB/CD over the last 10 years. The loss of about 25,000 of these jobs is directly attributable to refinery employment, and the balance to allied industries. This serious loss of employment opportunities would undoubtedly be accelerated if the United States commits itself to greater dependence on foreign processing capacity.

Modification of the Import Control System

Oil import policy and the implementing control system can be instrumental in promoting the long-term growth of domestic refining capacity, providing adequate economic incentives prevail to encourage refinery investment in the United States. With a growing dependence on foreign oil and with future increases in the prices of foreign supplies almost a foregone conclusion, refined product prices in the United States will have to ensure the refiner an adequate return on investment. Anything less will result in continued shortages of refining capacity to meet demand.

The Mandatory Oil Import Program alone is no longer an effective means for ensuring adequate supplies of petroleum to meet requirements in the United States. The complexity of the refining industry, the size and geography of the U.S. market, the rapidly changing supply conditions and the widespread location of inland refining capacity have made it increasingly difficult to administer a quota allocation system and, at the same time, ensure adequate supply to all refiners.

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* U.S. Department of the Interior, Office of Oil and Gas, *Trends in Capacity and Utilization*, December 1972.

Uncertainties concerning the future direction of import policy, uncertainties with respect to allocations within the existing system and quota restrictions limiting access to foreign supply have made it increasingly difficult for any refiner to realize the assured and adequate long-term supply of crude oil necessary for large scale expansion of refining capacity. The resulting lag in development of new refining capacity, coupled with the deficit in domestic raw material supply and the rapid increase in requirements for foreign crude oil, has created an urgent need for modificaiton of existing import controls.

Short-Term Considerations

Short-term considerations within the import control system have become critical in the last 6 to 12 months. This is evidenced by the growing shortages of both crude oil and products, by the necessity of eliminating controls on light heating oils for the first 4 months in 1973 and by the fact that the refining industry is operating at or close to maximum effective capacity.

With no substantial additions to capacity scheduled to come on-stream over the next several years, the growth in petroleum demand, at least through 1975, will have to be increasingly supplied by imports of finished products, assuming sufficient foreign refining capacity is available to meet these requirements. Lead time of at least 3 years to construct new large increments of refining capacity preclude any other possibilities at the present time to meet the normal short-term growth in petroleum demands. Revisions in the import program will be necessary to meet the short-term considerations of product shortages.

It is important to recognize, however, that product imports discourage the development of domestic refining capacity. At the same time, increased petroleum product imports are essential to meet demand over the near term. Changes in the import program to accommodate additional product imports have been necessary, but it is important that these changes be compatible with long-term goals and priorities of import policy. Adequate incentives to phase out the short-term increase in product imports will be necessary as additional domestic refineries are brought on-stream.

Long-Term Considerations

The NPC U.S. Energy Outlook Report recommended that import policies be designed to encourage the growth of domestic refining capacity by assuring refiners adequate access to long-term crude oil supplies. The extent to which product imports may be required to meet short-term considerations should not obviate the need for long-term policy guidelines to encourage the development of domestic refining capabilities.

Various proposals and recommendations to revise the import control system and make it more responsive to refinery requirements have been studied and considered. These proposals include, but are not limited to:

- Modification of the existing quota system with special incentives for development of U.S. refining capacity. Included are quota incentives for new refinery capacity, incentives for development of heavy fuel oil refineries, low-sulfur bonus proposals, etc.
- Elimination of formal quota controls on crude oil, a phase-out of product imports or alternatively a tariff on product imports, with provision for standby controls in the event that foreign productive capacity threatens the well-being of the domestic producing industry.
- A tariff system with a phase-out of formal quota controls.
- A quota-auction system or quota-tariff system.
- Elimination of crude quota controls by requiring each refiner to run a predetermined percentage of U.S. produced petroleum liquids.

It is not the intent of this study to evaluate the advantages or disadvantages of any of the specific proposals suggested, but to consider those guidelines essential to the long-term development of crude processing facilities. In order to be effective, any system of import controls, whether quota restrictions or variations thereof, should at the very least consider:

- More favorable provisions for importation of crude oil than refined products.
- Provisions to ensure a market for all domestic crude production.
- Policies that provide the domestic refiner assurances of an adequate and long-term supply of crude oil from domestic as well as foreign sources and, in so doing, assure maximum utilization of existing refining capacity.
- Incentives to offset the disadvantages faced by domestic refiners when manufacturing products currently exempt from formal quota control.
- A degree of consistency and stability in order to provide refiners the basis for establishing long-term planning objectives.
- Compatibility with overall objectives of energy policy.

NATURAL GAS POLICIES

Federal control of wellhead prices of natural gas at artificially low ceilings has contributed to (1) an inflated demand for gas relative to other energy fuels, (2) a reduction in exploration activity for new gas reserves, and thus (3) an accelerated depletion of existing reserves. As a result, shortfalls in natural gas supplies have become more frequent in recent years. With a continuance of the existing economic and political environment, the projected shortage in domestic supply is almostly directly proportional to the increase in future requirements.

Because of environmental considerations and other factors, oil has been and will continue to be required in increasing quantities to meet this shortfall in domestic gas supply. To this extent, the current shortage of gas, attributable to past federal policy, has contributed to inflating the demand for oil and attendant refining capacity.

Permitting field prices of natural gas to reach their competitive levels with other energy fuel sources would expand exploration efforts for new oil and gas reserves and future domestic supplies to meet market requirements. To the extent that additional domestic supplies of natural gas can effectively reduce the Nation's overall energy shortfall, there would be an equivalent reduction in the demand for oil and a reduction in required refinery capacity.

The U.S. is presently faced with short-term shortages of energy fuels and potential long-term deficits in available hydrocarbon resources. According to the NPC's U.S. Energy Outlook Report, the domestic oil supply deficit by 1985 could be as much as 19 MMB/CD (Case IV). The gas deficit could be as much as 7 trillion cubic feet (TCF) in 1985 depending on the level of demand.

While domestic oil and gas production has been adversely affected by lack of economic incentives, by infrequent Outer Continental Shelf (OCS) lease sales and by unrealistic environmental limitations, a reversal of such policies now is not apt to narrow significantly the supply/demand gap in the near term. This shortfall must necessarily be provided from foreign sources. The significant factor is the form in which that energy can and should be imported.

It should also be noted that the United States Supreme Court has decided in the United Gas Pipe Line Case that the Federal Power Commission (FPC) has authority to allocate sales of natural gas by interstate pipelines. An exercise of this jurisdiction based upon such allocation could dramatically modify existing fuel preferences and economic restraints. Inasmuch as FPC policy in this area has not been articulated in a meaningful way, it is impossible now to speculate upon the eventual effect of such possible action on demand by fuel types. All of these considerations lead to the possibility that both objectives and remedial actions concerning domestic refining capacity may have to be examined and considered on both short- and long-term bases.

Current import policies have encouraged offshore production of residual fuel. The resulting growth in offshore refining capacity has also provided substantial volumes of naphtha to meet local gasoline requirements, military grade jet fuels, feedstock for manufacture of petrochemical and unfinished oils for further processing in U.S. refineries. Under mandatory controls this material would only be imported by using quota licenses.

This report recognizes that neither the regasification of liquefied natural gas (LNG) nor the conversion of a liquid petroleum feedstock into synthetic natural gas (SNG) is considered to be domestic refining capacity per se. Though SNG facilities are not recognized as "refining capacity," those facilities could be considered an incentive for a refiner to locate incremental refining capacity onshore due to the synergistic benefits such facilities may have to a refining complex. Naturally, the incentive benefits of SNG facilities are conditioned upon a favorable federal regulatory policy on SNG. On the other hand, integration of LNG facilities within a refinery offers no incentive.

If the price of new gas were allowed to reach market clearing level, the effect on domestic refinery capacity should be beneficial in the long term. Gas prices would no longer be artificially low, and gas would probably be displaced in many of its low-cost energy applications by the refiner's products, such as distillate or residual fuel oil. This could result in a decreased demand for supplemental natural gas in the form of LNG and SNG. On the supply side, higher wellhead prices would stimulate more drilling for gas. This in turn, would result in additional domestic associated crude oil being discovered and produced. Higher domestic crude oil production would favor domestic refineries, especially those unfavorably located to receive foreign crude oils.

Liquefied Natural Gas

Liquefaction is a means of preparing natural gas for either shipment or storage. One cubic foot (0.177 barrels) of liquid methane, at -260°F and at 1 atmosphere pressure (atm), is the equivalent of approximately 630 standard cubic feet (SCF) of methane gas.

Present Regulatory Authority

The Department of the Interior does not currently have a regulatory policy on the importation of LNG. The FPC regulates LNG imports on a case-by-case basis; however, it does have authority pursuant to Section 3 of the Natural Gas Act to approve or disapprove imports of LNG, or to require imports to be made under conditions needed to protect the interests of consumers.

There are no present proposals before the FPC to import a major portion of total fuel requirements in the form of LNG. At present no imports have been finally authorized, except relatively small volumes to meet peaking requirements, and the first date on which imports could be received would be 1975. Given the above circumstances, there is no reason to modify the FPC's jurisdiction over LNG imports.

In 1972, the Commission approved the importation of Algerian LNG--equivalent to approximately 1 BCF/CD or almost 18 TCF for the life of the contracts.* The Commission (1) required incremental pricing of the substantially higher-cost LNG at the pipeline level instead of permitting it to be "rolled in" with the lower cost domestic supplies; and (2) limited the price to 77¢-83¢/MMBTU's, with provision only for a 1¢ increase in 1980. The FPC has not assumed jurisdiction of imported LNG that is not sold interstate. This may become a province of the state regulatory body.

Considerations

The FPC policy applicable to LNG, as set out in the Columbia LNG Opinion (particularly with respect to incremental pricing), exerts some effect on the construction of incremental refining capacity and could result in pressure for the emplacement of more U.S. refining capacity. If the importation fails, both the short-term and the long-term demand/supply gap, and the demand for other energy, will increase by the amount of energy lost from this source. In the event that such projects became feasible because of demands at incremental prices, LNG may be higher priced than alternative natural hydrocarbons such as naphtha, fuel oils and crude, and thus increase the demand for those energy sources.

LNG and other natural gas substitutes, even though incrementally priced and accepted, may have no substantial adverse effect on incremental domestic refining construction if short-term demands for gas cannot be practically satisfied by products from new domestic refineries. While the overall objective should be to encourage the maximum construction of domestic refining capacity, failure to expand refinery capacity in sufficient quantity to meet long-term demand could necessiate increasing the use of LNG as a substitute fuel.

Synthetic Natural Gas(SNG)

Synthetic natural gas is gas of pipeline quality manufactured for supplementing natural gas supplies and manufactured from light hydrocarbons, oils and coals.

Present Regulatory Authority

The Department of the Interior has no authority to regulate the manufacturing of SNG. The Foreign Trade Zones Board could approve a Foreign Trade Zone (FTZ) and the Office of Oil and Gas

*Columbia LNG Corporation, et al., Opinion Nos. 622 & 622A, Docket Nos. CP71-68, et al., June 28, 1972 & October 5, 1972.

would then be responsible for issuing an import license or licenses for withdrawal of the product from the FTZ.

Section 9 of the Oil Import Regulations provides that methane produced from oil is a petrochemical and thus may earn quota. A petrochemical plant earns 11.2 percent of its inputs in Districts I through IV and 11.9 percent of its inputs in District V. An SNG plant running Western Hemisphere butane and lighter or Canadian natural gas liquids would import without quota. The United States imposes no quantitative restrictions on crude or unfinished oils imported into District V from Canada.

The Federal Power Commission redered an Opinion on December 7, 1972, recommending that SNG should not come under FPC regulation until it is mixed with natural gas.* This is the first FPC opinion and order concerning jurisdiction over SNG. The opinion said that SNG is not "natural gas" within the meaning of the Natural Gas Act. The Act would not cover any aspect of the proposal, including SNG's proposed manufacture, or its transportation and sale in interstate commerce unmixed with natural gas. However, a mixture of natural and artificial gas would be considered natural gas subject to regulation.

The Commission will not regulate the purchase contract of the naphtha feedstock which would be domestic naphtha, but the feedstock supplier could not assure that the naphtha would be produced only from domestic crude. Algonquin proposed that the *higher*-priced ($1.80/MCF) SNG be used for peaking periods only, when regular supplies of lower priced ($0.70/MCF) gas are not available.

There was an assumption on the part of the pipeline companies that the SNG, an unconventional, higher-priced gas like LNG, if utilized for base load rather than "peaking" purposes, could be "rolled in" the domestic gas rates, but Commission language in the Columbia LNG Case suggesting that all unconventional gas be priced incrementally now casts doubt on that assumption. In the Tecon Case, the initial staff brief recommended that SNG be treated comparable to LNG, as in the Columbia LNG Case.

Considerations

The Oil Policy Committee is currently under pressure to authorize imports of naphtha, crude or both for conversion into SNG to supplement short domestic supplies. From the viewpoint of time, SNG from naphtha is a near-term (2-3 years) source of additional gas supplies in the United States. The primary foreign source of naphtha for most proposed SNG plants is from refiners who have a supply of naphtha that accompanies their residual oil production for shipment to the U.S. East Coast. The importation of naphtha, as well as other unfinished oils and finished products, has the effect of "exporting refining capacity" as the offshore refinery

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* Algonquin SNG, et.al., Opinion No. 637, Docket Nos. CP72-35, et al., December 7, 1972.

takes advantage of lower cost of construction and better harbor facilities. Thus, SNG would otherwise be made from domestic naphtha or would be replaced by other domestic products (e.g., distillate fuel) in the energy market.

On a long-term basis, a modification of the Oil Import Program to permit the quota-free importation of crude oil into special facilities, which would process the imported oils into residual fuel oil, SNG or other products not subject to quantitative import restrictions under Mandatory Oil Import Program, would provide necessary SNG without the resultant exportation of refining capacity.

The regulatory policies of the FPC respecting "incremental pricing," if extended to SNG projects, would have the same effect as they do in the case of LNG--that is, they would encourage the expansion of domestic refining capacity. The same consideration of energy need and timing discussed above with respect to LNG is applicable to SNG, except that gas from imported naphtha could be available in a shorter time period than LNG. Whether domestic refining capacity is a practical substitute for this energy source in this time period is problematical.

REFINERY SITING AND LAND USE

Local environmental restrictions and a growing antagonism on the part of some state and local governments and privately organized citizen groups to the location of heavy industry, such as refineries and electric power plants, have created serious problems for locating new facilities in the major energy markets of the East and West Coasts. With today's political, social and environmental climate, there are many restrictions imposed by regulatory authorities which are contributing to the shortfall of refining capacity. For example, California and Delaware have legislated coastal land-use laws that place major restrictions on the industrial use of coastal zones.

The NPC refinery survey revealed that very few companies were planning new refineries--eight refineries with a total of only 900 MB/CD capacity are in the planning stage industry-wide. Other companies reported that land was available, but that environmental considerations have forced them to defer any firm plans.

Survey data from the industry indicate that, in general, refinery expansion can take place at existing locations. These expansions are subject to the lengthy process of obtaining permits under local zoning and environmental ordinances and in accordance with all federal regulations. However, new grassroots refinery sites are difficult to obtain, particularly on the East and West Coasts where additional refining capacity is most needed. In these areas, local ordinances and state regulations, such as coastal zone acts, restrict construction within specified distances of the coastline and make the possibility of development of marine facilities very unlikely.

The East Coast (PAD District I) has the largest population and is in the least favorable position of any area with respect to energy self-sufficiency. In 1971, crude capacity was only 25.1 percent of product demand. About 2.0 MMB/CD of products were imported from offshore (87.5 percent of U.S. total product imports), and about 3 MMB/CD were brought in from the South and Southwest (PAD District III) by ship and pipeline. There has been essentially no significant growth in the refining capacity on the East Coast since import controls were adopted. Projections of petroleum product requirements indicate an increase between 1970 and 1985 of 4.8 MMB/CD. This represents 41.1 percent of the total growth for the United States during that time period.

If it is necessary to ship foreign crude oil to the Gulf Coast for refining and then back to the East Coast, there will be added costs. In view of the impending shortfall of refined products, the usual product allocation procedures or the attempt to fulfill the shortfall from foreign supply sources will impact more heavily on the East Coast consumer.

Several legislative bills before the Congress are specifically related to land-use planning of both private and federal lands. These bills would provide for:

- Land-use planning and management by the states
- Planning in terms of population growth, expanding urban development, industrial diversifications, etc.
- A means of overriding conflicting patterns of land use and lack of uniformity among governmental entities
- Exercising authority on the location and siting of key facilities by assuming local regulations do not unreasonably restrict land use.

Legislation of the type now under consideration would have little impact on the energy industry until at least 1980 because of procedures which essentially provide the states with lead time of at least 5 years to develop land-use plans. Even then, there is no assurance that such legislation would enable industry to develop adequate refining facilities.

Traditionally, the United States has placed primary reliance on the private sector for production, generation, distribution and marketing of energy and energy fuels. This reliance necessarily implies the availability of land for energy-related facilities. Proper land-use planning at both the state and federal levels is recognized as an important governmental function. However, such planning, in addition to meeting preservation, conservation and environmental goals, must make specific provisions for energy-related facilities for both public utilities and private business.

Construction Lead Time

Refinery equipment is, by its nature, large, complex and costly. Even under the best of circumstances, it takes a long time to plan for, design and construct a new process facility. For example, the construction of an alkylation plant with known technology and proved engineering takes 1.5 to 2.0 years. The lead time for a process using new technology can be 5 or more years when research is required.

Lead times are being lengthened by the need to file impact statements, obtain permits, hold public hearings and attend to all the complex administrative procedures established by federal, state and local agencies. It is estimated that the current lead time for a major process facility is 3 to 6 years.

Long lead times accentuate the importance of long-range planning. The lack of a national energy policy to establish goals, set priorities and help coordinate the interested federal, state and local agencies makes it difficult for the petroleum industry to effectively plan how to supply its share of the growing U.S. energy needs.

Coordination of Agencies Dealing with Energy

Prompt action should be taken to develop a comprehensive national energy policy and a coordinated, consistent program to accomplish national energy goals. The chief role of the government should be to establish priorities and guidelines and to eliminate the delays, conflicts and confusion that presently prevail among the many different federal, state and municipal agencies involved in energy matters.

Appendices

APPENDIX A

Request Letter

UNITED STATES DEPARTMENT OF THE INTERIOR
OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

February 9, 1972

Dear Mr. True:

The increasing dependency of this Nation on imported supplies of petroleum, both crude and refined products, the sources of which vary considerably in reliability, is a cause for serious concern. At the same time the United States appears to be increasing its dependence on refining facilities and capabilities located outside this country. This growing proportion of foreign manufactured petroleum products which are necessary for the economic well-being and security of this Nation is also a matter of increasing concern.

I therefore request that the Council undertake, as a matter of urgency, a survey of the factors--economic, governmental, technological and environmental--which may affect the domestic refining industry's ability to respond to the demands for essential petroleum products that are made upon it. The Council should discuss those elements which are deemed essential to a healthy domestic refining industry. To the extent that petroleum belonging to other phases of petroleum supply and consumption impinge upon growth and technological capabilities of the refining segments, these should be included in the analysis.

Representatives of the Department of the Interior will consult with you in the near future to arrive at a detailed outline of the matters relative to this general request.

Sincerely yours,

/s/ HOLLIS M. DOLE
Assistant Secretary of the Interior

Mr. H. A. True, Jr.
Acting Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

APPENDIX B

Committee Rosters

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APPENDIX C
Fundamentals of Refining Operations and Product Use

FUNDAMENTALS OF REFINING OPERATIONS AND PRODUCT USE

PAST HISTORY OF PRODUCT USE

The demand for petroleum products has grown enormously in the past 25 years in both volume and complexity. During this period, demand for all products has increased from less than 5 MMB/D to over 16 MMB/D in 1972. The most spectacular growth has been in the use of aviation fuels, where consumption has increased over 30 times the amount used at the end of World War II.

The quality of virtually all petroleum products has been improved significantly during this period, resulting in more efficiency with less polluting emissions such as those caused by sulfur.

Petroleum products are the major source of energy for transportation and are the raw materials for many of the products throughout our economy. They also provide a substantial part of the energy for the production of electrical power. They provide the mobility required for national security and contribute greatly to the economic welfare of our society.

The chief factors contributing to the rapidly growing demand for petroleum are the increasing population and the rapid growth in the demand for energy. The U.S. per capita demand for petroleum products has more than doubled since World War II.

The United States has become a nation on wheels. Four out of five workers use an automobile for commuting to and from work. Over 80 percent of the vacationing public use their own automobiles for transportation.

Air travel developed rapidly after World War II, causing rapid growth in the demand for aviation gasoline. The jet age began in the 1950's, creating a demand for an entirely new fuel. Faster and larger planes were required to supply the very rapidly increasing demand for air travel. Although Americans travel more than the rest of the world combined, air travel in the United States is still in the early stages of growth.

The demand for oils for space heating increased sharply after World War II, chiefly because of the switch from coal for home use. In 1946, 2.7 million homes in the United States were centrally heated with oil, increasing to 11.2 million by 1969.

The demand for residual fuel oils for heating large buildings rose substantially after World War II because of the large increase in new construction of such buildings. In the past few years, the demand for residual fuel oils has taken a sharp increase as a result of industrial and electrical power plant usage. Nuclear power generation has not developed as rapidly as previously anticipated, and coal has not been able to fill the increasing demand for low-sulfur fuels. During the 1946-1970 period, residual fuel oil experienced an overall growth rate of 2.2 percent per year. However, annual growth for this fuel increased 4.2 percent in 1971 and over 8.9 percent in 1972.

Liquefied petroleum gas (LPG) is a large-volume product which has experienced an overall growth rate since World War II of approximately 10 percent per year and has continued at a rate of about 5 percent per year since 1960.

PRODUCT DEVELOPMENT--CHARACTERISTICS AND IMPROVEMENTS

Motor Fuels

Motor Gasoline

Since World War II, gasoline has changed in hydrocarbon composition and is now a product made by careful blending of refinery stock prepared by involved new processes and special additives developed in extensive research programs. The most outstanding change in gasoline during this period has been a vast improvement in antiknock quality. Although the past benefits enjoyed by the consumer in terms of high-efficiency, high-performance automobiles are being eliminated in order to meet automobile pollution regulations, this octane quality not only is needed but will have to be increased to supply unleaded fuels of the future. Higher octanes have been obtained largely by new refining technology and processing, including better desulfurization of gasoline blending stocks, which has made the lead antiknock additives more effective. During this same period, the control of gasoline volatility has improved, contributing to better engine performance.

Special detergent or dispersant additives are now available to help maintain a clean carburetion system, resulting in improved engine performance, better mileage in city driving, reduced carburetor maintenance and reduced exhaust pollutants.

At present, there are proposed regulations limiting the lead alkyl content of future motor gasolines. In addition, one grade of unleaded gasoline must be available for public use by mid-1974. The primary reason for these considerations is the expectation that low-lead or unleaded fuels will permit operation of proposed pollution control systems on automobiles. Voluntary action on the part of the oil industry has already resulted in general availability of low-lead and unleaded gasolines. This trend will undoubtedly continue, bringing about increasing supplies of these types of fuels, and will result in major investments for proper process facilities. Further changes in motor fuel characteristics may be required. Such characteristics as sulfur content, volatility and boiling range may require further modifications to satisfy automobile pollution control system requirements.

Diesel Fuels

Like gasoline, distillate diesel fuels for use in automotive diesel engines have been improved during the past several years to meet requirements imposed by changes in engine design and operation. The most significant change in diesel fuels has been the use of hydrogen treating in refineries, primarily to reduce sulfur content. In addition, fuels have been gradually improved, resulting in decreased engine deposits, smoke and odor. Railroad diesel fuels have not changed significantly since the large diesel engines used in railroad service operate satisfactorily on fuels with less exacting specifications.

The use of additives in diesel fuels has become more common to provide improvements such as lower pour points, ignition quality and storage stability. Recent air pollution regulations have generated an increased interest in antismoking additives.

Other Petroleum Motor Fuels

LPG has been used as a motor fuel since the 1920's in bus, truck and taxi fleet operations which have central servicing centers. The use of compressed natural gas (CNG) and liquefied natural gas (LNG) as motor fuels is a recent development proposed for urban use in service vehicle fleets.

Aviation Fuels

Aviation Gasoline

Quality control is particularly important in aviation gasoline production. Antiknock control is especially critical because, unlike the motorist, the pilot is not able to hear an engine knock over the noise level. Other important quality factors are volatility, freezing point, heat of combustion and oxidation stability. Quality control surveillance and close process control have enabled the industry to produce a uniform-quality premium product.

Jet Fuels

Commercial kerosine was first used as a fuel in early development on jet aircraft since it provided the necessary volatility and was a readily available commercial product of rather uniform characteristics. Jet fuels are exposed to both high and low temperatures in use. Therefore, these fuels must have very low freezing points and must be stable when exposed to high temperatures. The JP-4 and JP-5 military jet fuels and equivalent commercial fuels have thermal stability properties satisfactory for operations up to speeds of Mach 2.

Industrial and Heating Fuels

Liquefied Petroleum Gas

LPG has taken on increased importance during the past few years. The extensive use of catalytic cracking and catalytic reforming processes and the growth in hydrocracking have resulted in large quantities in addition to the production from natural gas processing. Prior to the start of the tremendous growth in the use of LPG in ethylene production, its major use was in household and industrial fuel, although LPG has long been used to a limited extent as a motor fuel.

Distillate Fuel Oil

Distillate fuel oil can be defined as Nos. 1, 2 and 4 heating oils, diesel oil and industrial distillates. Grade No. 2 fuel oil is the designation given to the heating or furnace oil most commonly used for domestic and small commercial space heating.

The period since World War II has seen marked changes in both the quality of home heating oils and the manufacturing techniques employed in producing them. Domestic heating oil should form no sediment in storage and leave no measurable quantity of ash or other deposits on burning. It should be fluid at storage conditions encountered during the winter months. The composition of the product must be controlled to assist in reducing smoke emission. Low-sulfur content has become quite important. The fuel must have a light color, an attractive appearance and an acceptable odor. It is these properties, along with sulfur removal, which have undergone the greatest changes in the past 20 years.

In the early 1950's, hydrogen treating was adopted as a means of reducing the sulfur and nitrogen compounds content of distillate fuel oil. Through the use of this process, carbon residue is reduced to less than 0.10 percent. Hydrogen-treated products are of excellent quality from the standpoint of a change in both color and sludge formation during storage.

The superior processing techniques used in producing distillate fuel oils today, coupled with the improvements and developments in additives, result in a cleaner-burning product. The reduction in sulfur has contributed to the improvement of air quality.

Residual Fuels

Residual fuel oil can be defined as Nos. 5 and 6 heating oils, heavy diesel, heavy industrial and Bunker C fuel oils. Typically, these fuels are used to provide steam and heat for industry and large buildings, to generate electricity and to power ships.

Since World War II, refining processes in the United States have continued to favor the breaking up of the heavier residuum into lighter petroleum products until residual fuel amounts to less than 8 percent of the crude refined.

Methods of desulfurizing low metal-content residual oils have been developed and are being utilized as stringent air pollution regulations become more widespread. The oil industry and boiler manufacturers have stepped up their research and development efforts considerably in the areas of desulfurizing high metal-content fuel oil and stack gas desulfurization.

Other Petroleum Products

Petrochemical Feedstocks

Petrochemical feedstocks, such as benzene, toluene, xylene, ethane and propane, are used in such diverse products as synthetic rubber, synthetic fibers and plastics. Tremendous growth in the petrochemical industry over the last 10 years has resulted in many new and improved uses for petrochemicals.

Lubricants

Lubricants fall generally into three categories: automotive oils, industrial oils and greases. Engine oils, gear oil and automatic transmission fluids are three major lubrication products used in automotive operations. These products function to lubricate, seal, cool, clean, protect and cushion. Industrial oils are formulated to perform a broad range of functions under a variety of operating conditions. The major functions provided include lubrication, friction modification, heat transfer, dispersancy and rust prevention. Greases are basically gels and are composed of lubricating oil in a semirigid network of gelling agents such as soaps, clays and more recently, totally organic substances.

Petroleum Solvents

A variety of petroleum solvents are produced, and critical specifications are largely a function of the end-product use. For example, rigid specifications are required for petroleum solvents used in the paint industry. These products must contain no materials that would discolor pigments. They must possess low odor for interior paints. Control devices make it possible to maintain consistent product quality even under the most rigid specifications.

Asphalt

The heaviest fractions of a great many crude oils include natural bitumens or asphaltenes and are generally called asphalt. Actually this material is the oldest product of petroleum and has been used throughout recorded history. However, new uses and new demands for asphalt are continually being developed. The industry has satisfied these demands by changing processing and types of crudes and by improving storage, transportation and blending facilities.

A CRUDE OIL REFINERY*

Crude oil is a substance comprised of a very complex mixture of hydrocarbons, which are molecules consisting almost solely of carbon and hydrogen atoms in various arrangements. Crude oil contains thousands of different molecules of varying sizes, their size being determined by the number of carbon and hydrogen atoms aggregated together. As a result of the different sizes and configurations, the molecules boil at different temperatures. It can be assumed that most of the molecules boil between 100°F and something in excess of 1,500°F. Due to the complexity of the hydrocarbon mixtures, only a few of the smaller, lower boiling molecules are named.

Paraffinic type crude oil is generally of high °API gravity and low in sulfur content and contains a lesser amount of other contaminants such as metals and nitrogen. The straight-run gasoline derived from this type of crude oil is low in octane quality. The naphtha fraction is a poor reformer charge stock but an excellent SNG feedstock and cracking stock for olefins. The heavy naphtha and kerosine fractions give problems in meeting product freeze point specifications, and the diesel fuel fractions have problems in meeting pour point specifications. The residual fuel oils also have high pour points, and the asphalt quality is often poor. However, the heavy naphtha and kerosine have good smoke point characteristics, and the heavy naphtha, kerosine and light gas oil have high cetane indices. The volumes of residuals are low and often can be cracked without too much penalty.

The physical properties of naphthenic crude oils vary widely between different producing fields. They are generally of low °API gravity, may be either high or low in sulfur content, and are often high in nitrogen and metals. The straight-run gasolines from this source are higher in octane but often of lesser volume. The naphtha is excellent reforming charge stock. The heavy naphtha has a poor smoke point and cetane index, and should be reformed. The kerosine and light gas oils have very poor cetane indices and are not suitable for domestic distillates. Pour points and freeze points of this latter fraction are very low. The residual fuel oil may be of high or low volume, high or low sulfur content and, high in metal-content. The metals are corrosive to boiler tubes, and the use of high-sulfur fuel oils is becoming more restrictive. These crudes are the source of naphthenic lubricating oils, and their asphalt quality is often good.

Intermediate type crude oils are, as their name implies, somewhere in between the paraffinic and naphthenic type crudes. These crudes generally will fall in the medium to high gravity range. Sulfur content may fall between 0.1 and 2.5 weight-percent sulfur. The distillate from these crudes generally has pour point and cetane index characteristics suitable for burning oil and diesel fuel. Figure 27 illustrates the differences between a typical intermediate crude oil and a typical naphthenic crude oil.

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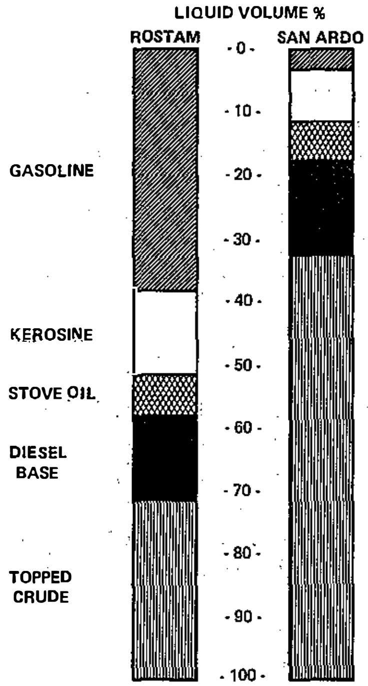
* Terms used in this section are defined in the Glossary.



CRUDE	ROSTAM	SAN ARDO	REMARKS
Gravity (°API)	38	13	
Sulfur (wt. %)	1.5	2.0	
Type	Intermediate	Naphthenic	
Gasoline (60-400°F)			
Octane	69.1	79.3	San Ardo gasoline is only 3 percent of crude and high in sulfur content.
Naphthenes	20%	74%	
Aromatics	16%	12%	
Reid Vapor Pressure	4.9	1.0	
Sulfur (wt. %)	0.05	0.33	
Kerosine (400-500°)			
Gravity (°API)	42	31	San Ardo distillate is not salable due to failure to meet °API, sulfur and cetane specifications because of the naphthenic nature of the crude.
Viscosity @ 100°F	33SUS	35SUS	
Sulfur (wt. %)	0.30	0.57	
Stove Oil (400-550°)			
Gravity (°API)	40	29	
Viscosity @ 100°F	35SUS	43SUS	
Sulfur (wt. %)	0.47	0.76	
Pour Point	−27°F	−45°F	
Diesel Base (500-650°)			
Gravity (°API)	36	26	
Pour Point	+25°F	−25°F	
Cetane	53.5	41.5	
Sulfur (wt. %)	0.92	1.01	
Viscosity @ 100°F	39 SUS	54 SUS	
Topped Crude (650°F+)			
Gravity (°API)	16	9	
Sulfur (wt. %)	3.3	2.2	
Viscosity @ 122°F	99SFS	1800 SFS	
Pour Point	70°F	80°F	

Figure 27. Crude Oil Characteristics.

In addition to the paraffinic, naphthenic and intermediate types of crude oils already discussed, there exist many combinations of these crudes. The Bureau of Mines categorizes oils in the following classifications:

- Paraffin--Paraffin
- Paraffin--Intermediate
- Paraffin--Naphthenic
- Intermediate--Paraffin
- Intermediate--Intermediate
- Intermediate--Naphthenic
- Naphthene--Intermediate
- Naphthene--Paraffin.

Crude oils are also classified as low-sulfur content (below 0.5 weight-percent sulfur), intermediate-sulfur content (between 0.5 and 1.0 weight-percent sulfur) and high-sulfur content (over 1.0 weight-percent sulfur). In general, the definition of a sweet crude oil is one that does not contain hydrogen sulfide and has below 0.5 weight-percent sulfur content, with only a minor portion of the sulfur content being present as mercaptans. Mercaptans (sulfur compounds) are one of the most undesirable contaminants of crude oil and petroleum products.

Each refinery processes a different mixture of crude oils, and over a period of time a processing sequence has been developed which converts these particular crude oils into the products required by consumers in the marketing area served. Therefore, it is not meaningful to attempt to describe the operation of an "average" refinery. The following discussion uses instead a simple-example refinery for its illustrative purposes. Figure 28 graphically shows the flow within the example refinery.

When the crude oil is charged into this refinery, the first processing equipment it reaches is called a crude oil distillation unit. The purpose of the crude unit is to separate the crude oil into at least four different boiling range fractions. The first fraction contains the lower boiling materials and is termed straight-run gasoline. This lower boiling fraction is then further processed into a finished gasoline blend stock. The next fraction boils between 400°F and 650°F and is called the straight-run distillate fraction. This distillate fraction is the material that is primarily sold as kerosine, jet fuel, heating oil (No. 1 and No. 2 fuel oil), and diesel fuel.

The next heavier fraction, which boils between 650°F and 850°F, is called the gas oil fraction. It is somewhat difficult to define gas oil, except to say that it is usually the material that is heavier than the distillate fraction and is not a black residual fuel oil. There is no consumer market for gas oil. Since it is too high boiling to be sold as distillate and too valuable to be sold as residual fuel oil, it is necessary to convert this fraction into something that can be utilized in the marketplace. To accomplish this the molecules are cracked (molecularly ruptured) into smaller-size molecules boiling in the gasoline and No. 2 fuel oil boiling range. The heaviest fraction from the crude unit is usually referred to as the residuum. This includes materials that boil at 850°F to the heaviest material in the barrel of crude, which boils at temperatures in excess of 1,500°F.

After the crude has been separated into these four fractions, each fraction is further processed to yield a product slate that can be accommodated in the market. The actual refined product distribution varies considerably, depending upon the exact nature of the crude oil that is available and the demands in the marketing area surrounding the refinery.

Many years ago, the straight-run gasoline fraction was used directly as automotive gasoline. Technological developments have now made this material unsuitable for modern day engines. Today, it is necessary to process the straight-run gasoline by molecular rearrangement and by making certain changes in the molecules that

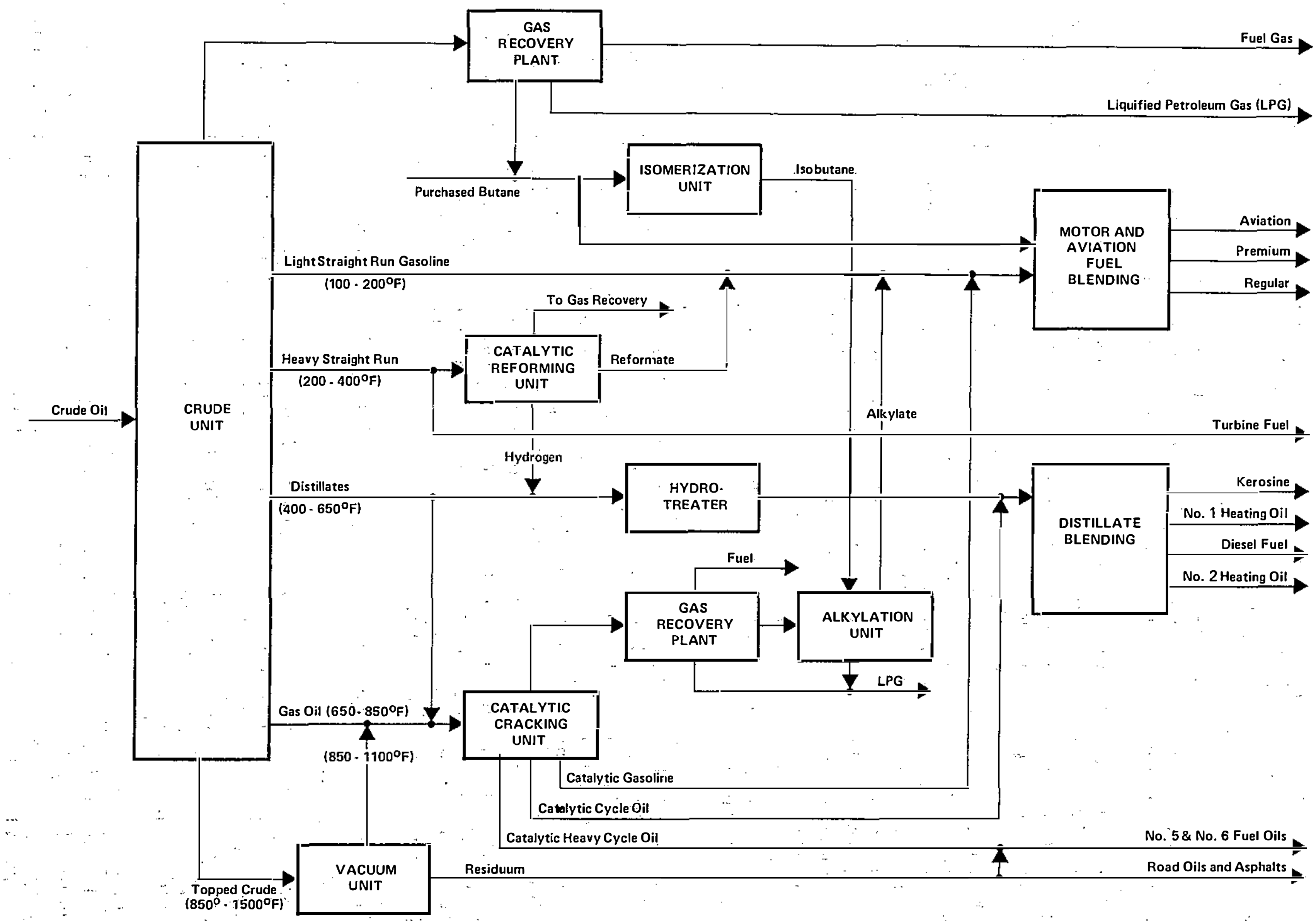


Figure 28. Process Flow--Example Refinery.

will increase the octane number. This is usually accomplished by sending the straight-run gasoline to a fractionator and separating it into two fractions. The lower boiling fraction, boiling between 100°F and 200°F, is called light, straight-run gasoline and has ordinarily gone directly into automotive gasoline. Although the octane number is not extremely high, light, straight-run gasoline can be included in finished gasoline. However, under proposed no lead regulations, additional processing will be required to increase the clear (no lead) octane rating of the straight-run gasoline.

The remaining portion of the straight-run gasoline boiling between 200°F and 400°F is sent to a catalytic reformer. The catalytic reformer uses a very expensive catalyst containing platinum. The heavy gasoline is first mixed with hydrogen and the temperature increased to over 900°F. When it is passed over the platinum catalyst, hydrogen is removed from some of the compounds, greatly increasing the octane number. When performing this operation, some of the molecules rupture, producing propane and butane which are then sold as liquefied petroleum gases. On a lead-free basis, the usual range of research octane numbers in gasoline resulting from this process is 90 to 100. Once the platinum catalyst has been used for a considerable length of time, it becomes economically unusable and must be rejuvenated or replaced.

The next heavier fraction from the crude still is the distillate fraction. Ordinarily, the distillates are treated to improve color stability and reduce the sulfur content to very low levels. The process whereby this treatment is accomplished is called hydrodesulfurization. This process consists of mixing hydrogen with the distillate at an elevated temperature of between 600°F and 700°F, then passing the hydrogen-distillate mixture over a catalyst containing the metals cobalt and molybdenum. The sulfur contained in the distillate reacts with the hydrogen to form hydrogen sulfide gas. This gas is then collected with various other refinery gases and sent to a central unit where the sulfur is removed as elemental sulfur. This elemental sulfur is a basic raw material used in many industrial applications. The treated distillates are fractionated to specifications for space heating oil, industrial heating oil and diesel fuel.

Gas oil, the next higher boiling range fraction from the crude still, is converted into marketable products by processing in a unit called a catalytic cracking unit. The catalyst used in most installations is a finely divided material that has a consistency similar to that of fine sand. It is generally composed of silica and alumina, the principal components of naturally occurring clay. The newer catalyst used today is modified into particular crystalline structures, greatly enhancing the value of the catalyst to a refiner by improving the yields of gasoline, which in turn increases the value of the total products from the catalytic cracking unit. The objective of this unit is to reduce the molecular size of the gas oil by rupturing or cracking the molecules and thereby lowering their boiling points into the gasoline and distillate boiling range. The gasoline from the catalytic cracking unit goes directly to the motor gasoline pool and has an octane number--between 88 and 94 on a tetraethyl lead-free basis. In this process, there is also produced a considerable amount of fuel gas that can be used as refinery fuel and a rather large volume of propane and butane fractions which also contain the olefins propylene and butylene.

Olefins are molecules from which a part of the hydrogen has been removed. These olefins are reacted with isobutane (a four-carbon molecule where the carbon atoms are not in a straight line but are what is termed "branched hydrocarbons"). This isobutane may be made to react with hydrogen deficient molecules of butylene to make isooctane, or with propylene to make isoheptanes. The isoparaffin mixture processed from this reaction is termed alkylate and is used for blending premium gasoline. It has also been used for many years as the principal high octane component of aviation gasolines. The octane number of the alkylate usually ranges from 92 to 95 with no tetraethyl lead.

Not all of the gas oil is converted into gasoline and alkylation unit feed in the fluid catalytic cracker. Part of the gas oil feed is only reduced in boiling range to a range comparable to that of the distillate fraction from the crude oil, and this material is the principal base stock for No. 2 heating oil. A small amount of very heavy fuel oil is made, which is a distillate fuel, but this is usually blended in with residual type fuel oil for sale.

The fourth and highest boiling fraction from the crude oil--topped crude--is processed in several different ways, depending upon geographic location of the refinery and the market demands of the area. This extremely high boiling fraction of the crude oil can be further processed through a vacuum distillation unit. The purpose of the vacuum unit is to allow vaporization of more of the heavier gas oil molecules from the crude residue without thermal disintegration of the molecules. The hydrocarbons vaporized can be included in the fluid catalytic cracker as additional gas oil feedstock. The heavier residual bottoms can be further processed into various kinds of fuel oil, primarily No. 6 or bunker fuel oil, and/or asphalt. The residual bottoms may also be coked, producing additional gasoline, distillates and solid petroleum coke.

The refinery described above is of the simplest form. Many specialty products--such as solvents--can be made in a refinery. Special processing can be performed to recover a variety of aromatics, including benzene, toluene and xylenes, for which there is a demand in the petrochemical markets. Typical boiling ranges for the major petroleum products are shown in Figure 29.

Several gasoline streams of varying quality can be produced from this refinery which can be blended in various proportions for making the different grades of gasoline and achieving desirable characteristics in each of the marketable grades.

Each petroleum refinery processes a different type of crude oil, and each refinery uses different amounts and types of conversion units. The conversion units are designed on the basis of converting the particular hydrocarbons in the available crude oil to the volume and type of products required by the consumer.

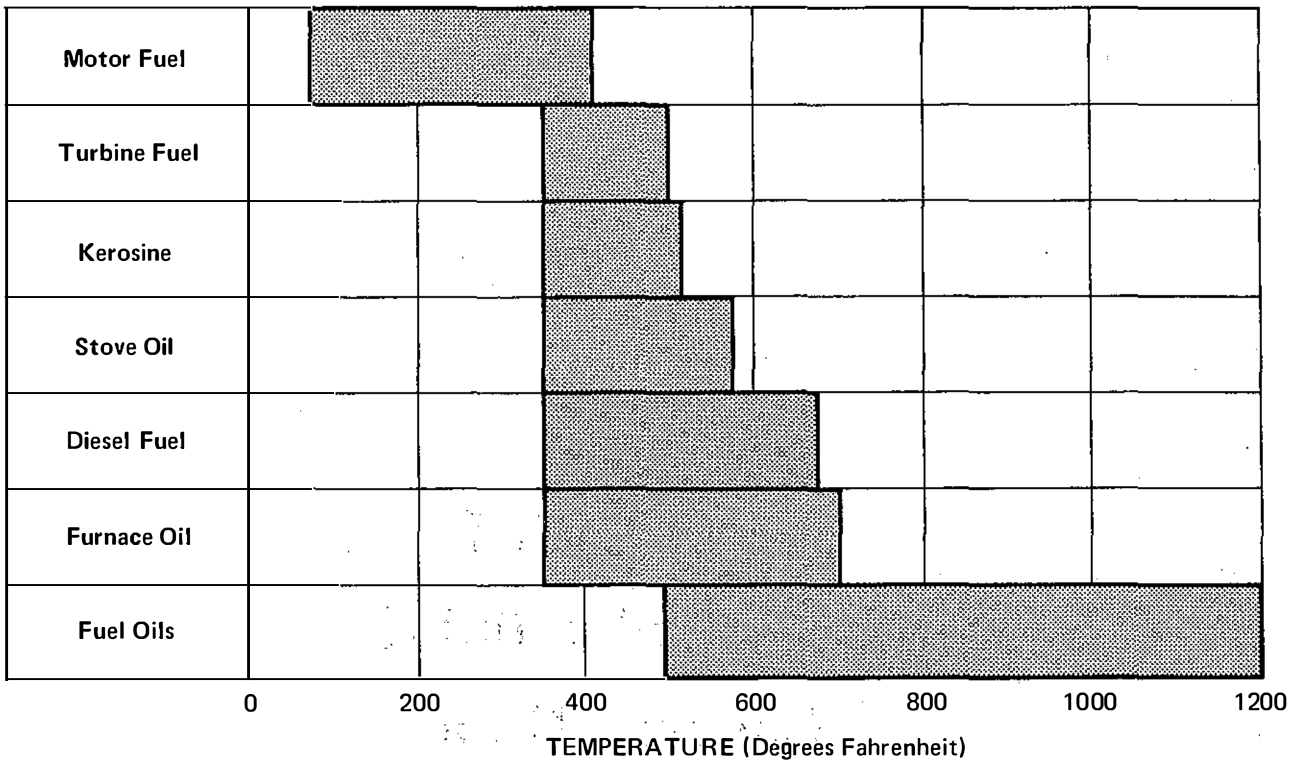


Figure 29. Typical Product Boiling Ranges.

APPENDIX D
Historical Refining Capacity Data

TABLE 50

HISTORICAL REFINING CAPACITY DATA—TOTAL UNITED STATES

	No. of Operating Refineries	Beginning Operating Capacity (Bbls/Day)	Shutdown Capacity		Additions			Grassroots			Total Additions		
			Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%
1962	287	9,793,748*	292,899	3.0	64	211,119	2.2	4	26,500	.3	68	237,619	2.4
1963	287	9,814,791	303,530	3.1	61	233,775	2.4	3	142,100	1.4	64	375,875	3.8
1964	282	10,063,164	322,210	3.2	54	357,731	3.6	6	197,950	2.0	60	555,681	5.6
1965	273	10,161,311	613,284	6.0	56	139,596	1.4	1	700	.0	57	140,296	1.4
1966	267	10,171,159	321,580	3.2	82	428,663	4.2	1	1,000	.0	83	429,663	4.2
1967	260	10,412,447	347,160	3.3	91	665,313	6.4	12	202,250	1.9	103	867,563	8.3
1968	270	11,172,694	360,160	3.2	88	492,114	4.4	1	800	.0	89	492,914	4.4
1969	264	11,575,829	163,680	1.4	73	412,146	3.6	1	89,000	.8	74	501,146	4.3
1970	262	11,882,393	191,930	1.6	81	814,149	6.9	3	280,000	2.4	84	1,094,149	9.2
1971	253	12,658,248	361,730	2.9	54	418,250	3.3	5	272,500	2.2	59	690,750	5.5
10-Yr. Summary†		9,793,748			704	4,172,856	42.7	38	1,212,800	12.4	742	5,385,656	55.0
Compounded Annual Rate of Increase or (Decrease)							3.6			1.2			4.5

	Capacity Lost Through Total or Partial Refinery Shutdowns			Capacity Lost Through Consolidations			Other Declines in Capacity			Total Declines			Net Increase or (Decrease)		Ending Operating Capacity (Bbls/Day)
	No.	Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%	Bbls/Day	%	
1962	5	57,300	.6	3	10,250	.1	31	149,026	1.5	39	216,576	2.2	21,043	.2	9,814,791
1963	8	49,900	.5	1	1,100	.0	21	76,502	.8	30	127,502	1.3	248,373	2.5	10,063,164
1964	14	113,044	1.1	9	273,280	2.7	28	71,210	.7	51	457,534	4.5	98,147	1.0	10,161,311
1965	4	44,300	.4	2	7,000	.1	19	79,148	.8	25	130,448	1.3	9,848	.1	10,171,159
1966	6	57,200	.6	2	40,500	.4	21	90,675	.9	29	188,375	1.9	241,288	2.4	10,412,447
1967	2	3,500	.0	2	80,400	.8	18	23,416	.2	22	107,316	1.0	760,247	7.3	11,172,694
1968	10	46,650	.3	1	2,000	.0	19	41,129	.4	30	89,779	.7	403,135	3.6	11,575,829
1969	6	40,600	.4	1	20,600	.2	22	133,382	1.2	29	194,582	1.7	306,564	2.7	11,882,393
1970	11	102,300	.9	2	120,900	.1	18	95,094	.8	31	318,294	2.7	775,855	6.5	12,658,248
1971	7	58,300	.5	1	72,000	.6	29	183,880	1.4	37	314,180	2.5	376,570	3.0	13,034,818
10-Yr. Summary†	73	573,094	5.9	24	628,030	6.4	226	943,462	9.6	323	2,144,586	21.8	3,241,070	33.1	13,034,818
Compounded Annual Rate of Increase or (Decrease)			.5			.6			.9			2.0		2.9	

*1/1/62 capacity later revised by Bureau of Mines to 9,812,248 B/D.

†10-Year Summary percentages are based on 1962 beginning operating capacity.

Source: U.S. Bureau of Mines, "Petroleum Refineries in the United States," *Mineral Industries Survey*, published annually.

TABLE 51

HISTORICAL REFINING CAPACITY DATA–DISTRICT I

	No. of Operating Refineries	Beginning Operating Capacity (Bbls/Day)	Shutdown Capacity		Additions			Grassroots			Total Additions		
			Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%
1962	35	1,577,990	57,300	3.6	9	21,500	1.4	0	0	0	9	21,500	1.4
1963	36	1,507,140	75,000	5.0	4	14,450	1.0	0	0	0	4	14,450	1.0
1964	36	1,479,790	75,000	5.0	8	147,000	10.0	0	0	0	8	147,000	10.0
1965	34	1,448,640	225,400	16.0	5	7,960	.5	0	0	0	5	7,960	.5
1966	32	1,391,000	143,700	10.0	7	32,300	2.3	0	0	0	7	32,300	2.3
1967	31	1,409,300	155,700	11.0	7	17,600	1.2	0	0	0	7	17,600	1.2
1968	31	1,423,100	126,300	8.9	11	57,600	4.0	0	0	0	11	57,600	4.0
1969	31	1,479,720	54,000	3.6	7	24,700	1.7	0	0	0	7	24,700	1.7
1970	31	1,473,220	36,000	2.4	8	30,200	2.0	0	0	0	8	30,200	2.0
1971	30	1,501,420	0	0	7	133,000	8.9	0	0	0	7	133,000	8.9
10-Yr. Summary*		1,577,990			73	486,310	30.8	0	0	0	73	486,310	30.8
Compounded Annual Rate of Increase or (Decrease)							2.8						2.8

	Capacity Lost Through Total or Partial Refinery Shutdowns			Capacity Lost Through Consolidations			Other Declines in Capacity			Total Declines			Net Increase or (Decrease)		Ending Operating Capacity (Bbls/Day)
	No.	Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%	Bbls/Day	%	
1962	1	31,000	2.0	1	5,000	.3	5	56,350	3.6	7	92,350	5.9	(70,850)	(4.5)	1,507,140
1963	0	0	0	0	0	0	5	41,800	2.8	5	41,800	2.8	(27,350)	(1.8)	1,479,790
1964	3	51,000	3.5	4	113,400	7.7	4	13,750	1.0	11	178,150	12.0	(31,150)	(2.0)	1,448,640
1965	1	27,300	1.9	0	0	0	5	38,300	2.6	6	65,600	4.5	(57,640)	(4.0)	1,391,000
1966	1	12,000	.9	0	0	0	4	2,000	.1	5	14,000	1.0	18,300	1.3	1,409,300
1967	0	0	0	0	0	0	3	3,800	.3	3	3,800	.3	13,800	1.0	1,423,100
1968	0	0	0	0	0	0	3	980	.1	3	980	.1	56,620	4.0	1,479,720
1969	0	0	0	0	0	0	4	31,200	2.1	4	31,200	2.1	(6,500)	(.4)	1,473,220
1970	0	0	0	0	0	0	1	2,000	.1	1	2,000	.1	28,200	2.0	1,501,420
1971	1	33,000	2.2	1	72,000	4.8	3	900	.1	5	105,900	7.1	27,100	1.8	1,528,520
10-Yr. Summary*	7	154,300	10.0	6	190,400	12.1	37	191,080	12.1	50	535,780	34.0	(49,470)	(3.1)	1,528,520
Compounded Annual Rate of Increase or (Decrease)			.9			1.15			1.15			3.0		(.3)	

* 10-Year Summary percentages are based on 1962 beginning operating capacity

Source: U.S. Bureau of Mines, "Petroleum Refineries in the United States," *Mineral Industries Survey*, published annually.

TABLE 52

HISTORICAL REFINING CAPACITY DATA—DISTRICT II

	No. of Operating Refineries	Beginning Operating Capacity (Bbls/Day)	Shutdown Capacity Bbls/Day	Shutdown Capacity %	Additions No.	Additions Bbls/Day	Additions %	Grassroots No.	Grassroots Bbls/Day	Grassroots %	Total Additions No.	Total Additions Bbls/Day	Total Additions %
1962	92	2,783,100	91,875	3.3	30	92,295	3.3	0	0	0	30	92,295	3.3
1963	90	2,833,669	69,580	2.5	21	55,985	2.0	0	0	0	21	55,985	2.0
1964	88	2,860,154	63,400	2.2	18	71,490	2.5	1	450	0	19	71,940	2.5
1965	85	2,878,870	101,024	3.5	20	62,700	2.2	0	0	0	20	62,700	2.2
1966	84	2,912,870	70,880	2.4	28	170,220	5.8	0	0	0	28	170,220	5.8
1967	79	2,988,515	69,560	2.3	31	200,285	6.7	1	7,500	.3	32	207,785	7.0
1968	79	3,108,750	134,510	4.3	29	139,230	4.5	0	0	0	29	139,230	4.5
1969	78	3,211,580	55,880	1.7	25	131,033	4.1	0	0	0	25	131,033	4.1
1970	73	3,226,531	76,980	2.4	29	237,149	7.3	2	250,000	7.8	31	487,149	15.1
1971	70	3,492,670	220,980	6.3	13	50,520	1.5	0	0	0	13	50,520	1.5
10-Yr. Summary*		2,783,100			244	1,210,907	43.5	4	257,950	9.3	248	1,468,857	52.8
Compounded Annual Rate of Increase or (Decrease)							3.7			.9			4.34

	Capacity Lost Through Total or Partial Refinery Shutdowns No.	Bbls/Day	%	Capacity Lost Through Consolidations No.	Bbls/Day	%	Other Declines in Capacity No.	Bbls/Day	%	Total Declines No.	Bbls/Day	%	Net Increase or (Decrease) Bbls/Day	%	Ending Operating Capacity (Bbls/Day)
1962	4	26,300	.1	2	5,250	.2	7	10,176	.4	13	41,726	1.5	50,569	1.8	2,833,669
1963	4	17,900	.6	0	0	0	4	11,600	.4	8	29,500	1.0	26,485	.9	2,860,154
1964	5	28,744	1.0	2	12,880	.5	7	11,600	.4	14	53,224	1.9	18,716	.7	2,878,870
1965	1	5,000	.2	1	6,000	.2	5	17,700	.6	7	28,700	1.0	34,000	1.2	2,912,870
1966	4	31,700	1.1	0	0	0	7	62,875	2.2	11	94,575	3.3	75,645	2.6	2,988,515
1967	1	1,500	.1	1	80,000	2.7	5	6,050	.2	7	87,550	2.9	120,235	4.0	3,108,750
1968	4	29,400	.1	0	0	0	4	7,000	.2	8	36,400	1.2	102,830	3.3	3,211,580
1969	3	21,100	.7	0	0	0	10	94,982	3.0	13	116,082	3.6	14,951	.5	3,226,531
1970	5	82,000	2.5	1	72,400	2.2	4	66,610	2.1	10	221,010	6.9	266,139	8.3	3,492,670
1971	1	8,000	.2	0	0	0	10	65,100	1.9	11	73,100	2.1	(22,580)	(.7)	3,470,090
10-Yr. Summary*	32	251,644	9.0	7	176,530	6.3	64	358,993	12.7	102	781,867	27.9	686,990	24.7	3,470,090
Compounded Annual Rate of Increase or (Decrease)			.85			.5			1.2			2.5		2.2	

* 10-Year Summary percentages are based on 1962 beginning operating capacity.

Source: U.S. Bureau of Mines, "Petroleum Refineries in the United States," *Mineral Industries Survey*, published annually.

TABLE 53

HISTORICAL REFINING CAPACITY DATA–DISTRICT III

	No. of Operating Refineries	Beginning Operating Capacity (Bbls/Day)	Shutdown Capacity		Additions			Grassroots			Total Additions		
			Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%
1962	86	3,561,925	125,100	3.5	11	75,400	2.1	3	25,000	.7	14	100,400	2.8
1963	87	3,588,525	142,800	4.0	19	84,000	2.3	2	122,100	3.4	21	206,100	5.7
1964	85	3,752,875	175,300	4.7	14	102,200	2.7	2	146,000	3.9	16	248,200	6.6
1965	85	3,858,190	205,500	5.3	16	33,437	.9	0	0	0	16	33,437	.9
1966	84	3,872,119	61,000	1.6	31	158,863	4.1	1	1,000	0	32	159,863	4.1
1967	84	3,967,282	71,000	1.8	31	398,978	10.1	6	156,000	3.9	37	554,978	14.0
1968	90	4,513,514	61,000	1.4	26	168,734	3.7	0	0	0	26	168,734	3.7
1969	86	4,648,099	25,500	.5	25	213,083	4.6	0	0	0	25	213,083	4.6
1970	86	4,825,782	55,700	1.2	29	488,960	10.1	0	0	0	29	488,960	10.1
1971	82	5,227,258	122,500	2.3	21	188,830	3.6	2	161,500	3.1	23	350,330	6.7
10-Yr. Summary*		3,561,925			223	1,912,485	53.7	16	611,600	17.2	239	2,524,085	70.9
Compounded Annual Rate of Increase or (Decrease)							4.4			1.65			5.5

	Capacity Lost Through Total or Partial Refinery Shutdowns			Capacity Lost Through Consolidations			Other Declines in Capacity			Total Declines			Net Increase or (Decrease)		Ending Operating Capacity (Bbls/Day)
	No.	Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%	Bbls/Day	%	
1962	0	0	0	0	0	0	15	73,800	2.1	15	73,800	2.1	26,600	.8	3,588,525
1963	4	32,000	.9	1	1,100	0	6	8,650	.2	11	41,750	1.2	164,350	4.6	3,752,875
1964	1	2,000	.1	1	109,000	2.9	8	31,885	.9	9	142,885	3.8	105,315	2.8	3,858,190
1965	2	12,000	.3	0	0	0	4	7,508	.2	6	19,508	.5	13,929	.4	3,872,119
1966	0	0	0	2	40,500	1.1	7	24,200	.6	9	64,700	1.7	95,163	2.5	3,967,282
1967	0	0	0	0	0	0	5	8,746	.2	5	8,746	.2	546,232	13.8	4,513,514
1968	4	11,000	.2	0	0	0	11	23,149	.5	16	34,149	1.6	134,585	3.0	4,648,099
1969	2	14,500	.3	1	20,600	.4	2	300	0	5	35,400	.8	177,683	3.8	4,825,782
1970	4	18,300	.4	1	48,500	.1	7	20,684	.4	12	87,484	1.8	401,476	8.3	5,227,258
1971	3	8,000	.2	0	0	0	9	106,830	2.0	12	114,830	2.2	235,500	4.5	5,462,758
10-Yr. Summary*	20	97,800	2.7	6	219,700	6.2	74	305,752	8.6	100	623,252	17.5	1,900,833	53.0	5,462,758
Compounded Annual Rate of Increase or (Decrease)			.25			.5			.8			1.65		4.34	

* 10-Year Summary percentages are based on 1962 beginning operating capacity.

Source: U.S. Bureau of Mines, "Petroleum Refineries in the United States," *Mineral Industries Survey*, published annually.

TABLE 54

HISTORICAL REFINING CAPACITY DATA—DISTRICT IV

	No. of Operating Refineries	Beginning Operating Capacity (Bbls/Day)	Shutdown Capacity Bbls/Day	Shutdown Capacity %	Additions No.	Additions Bbls/Day	Additions %	Grassroots No.	Grassroots Bbls/Day	Grassroots %	Total Additions No.	Total Additions Bbls/Day	Total Additions %
1962	30	357,431	5,324	1.5	6	4,974	1.4	1	1,500	.4	7	6,474	1.8
1963	31	361,705	4,850	1.3	6	24,600	6.8	0	0	0	6	24,600	6.8
1964	31	384,605	3,050	.8	4	7,020	1.8	2	6,500	1.7	6	13,520	3.5
1965	28	385,050	13,600	3.5	3	2,700	.7	1	700	.2	4	3,400	.9
1966	29	386,950	12,600	3.3	9	11,500	3.0	0	0	0	9	11,500	3.0
1967	28	384,450	25,100	6.5	11	17,350	4.5	1	5,000	1.3	12	22,350	5.8
1968	29	402,580	25,550	6.3	9	26,800	6.7	0	0	0	9	26,800	6.7
1969	28	422,380	15,550	3.7	7	6,530	1.5	0	0	0	7	6,530	1.5
1970	27	421,610	19,750	4.7	6	9,990	2.4	0	0	0	6	9,990	2.4
1971	26	425,300	8,750	2.1	3	6,900	1.6	0	0	0	3	6,900	1.6
10-Yr. Summary*		357,431			64	118,364	33.1	5	13,700	3.8	69	132,064	37.0
Compounded Annual Rate of Increase or (Decrease)							2.9			.3			3.3

	Capacity Lost Through Total or Partial Refinery Shutdowns No.	Bbls/Day	%	Capacity Lost Through Consolidations No.	Bbls/Day	%	Other Declines in Capacity No.	Bbls/Day	%	Total Declines No.	Bbls/Day	%	Net Increase or (Decrease) Bbls/Day	%	Ending Operating Capacity (Bbls/Day)
1962	0	0	0	0	0	0	2	2,200	.6	2	2,200	.6	4,274	1.2	361,705
1963	0	0	0	0	0	0	2	1,700	.5	2	1,700	.5	22,900	6.3	384,605
1964	2	6,000	1.6	1	5,000	1.3	4	2,075	.5	7	13,075	3.4	445	.1	385,050
1965	0	0	0	0	0	0	1	1,500	.4	1	1,500	.4	1,900	.5	386,950
1966	1	13,500	3.5	0	0	0	1	500	.1	2	14,000	3.6	(2,500)	(.6)	384,450
1967	0	0	0	1	400	.1	3	3,820	1.0	4	4,220	1.1	18,130	4.7	402,580
1968	1	5,000	1.2	1	2,000	.5	0	0	0	2	7,000	1.7	19,800	4.9	422,380
1969	1	5,000	1.2	0	0	0	3	2,300	.5	4	7,300	1.7	(770)	(.2)	421,610
1970	1	1,000	.2	0	0	0	5	5,300	1.3	6	6,300	1.5	(3,690)	.9	425,300
1971	0	0	0	0	0	0	5	9,550	2.2	5	9,550	2.2	(2,650)	(.6)	422,650
10-Yr. Summary*	6	30,500	8.5	3	7,400	2.1	26	28,945	8.1	35	66,845	18.7	65,219	18.0	422,650
Compounded Annual Rate of Increase or (Decrease)			.8			.2			.8			1.7		1.7	

* 10-Year Summary percentages are based on 1962 beginning operating capacity.

Source: U.S. Bureau of Mines, "Petroleum Refineries in the United States," *Mineral Industries Survey*, published annually.

TABLE 55

HISTORICAL REFINING CAPACITY DATA—DISTRICT V

	No. of Operating Refineries	Beginning Operating Capacity (Bbls/Day)	Shutdown Capacity		Additions			Grassroots			Total Additions		
			Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%
1962	44	1,513,302	13,300	0	8	16,950	1.1	0	0	0	8	16,950	1.1
1963	43	1,523,752	11,300	.7	11	54,740	3.6	1	20,000	1.3	12	74,740	4.9
1964	42	1,585,740	5,460	.3	10	30,021	1.9	1	45,000	2.8	11	75,021	4.7
1965	41	1,590,561	67,760	4.3	12	32,799	2.1	0	0	0	12	32,799	2.1
1966	38	1,608,220	33,400	2.1	7	55,780	3.5	0	0	0	7	55,780	3.5
1967	38	1,662,900	25,800	1.6	11	31,100	1.9	4	33,750	2.0	15	64,850	3.9
1968	41	1,724,750	12,800	.7	13	99,750	5.8	1	800	0	14	100,550	5.8
1969	41	1,814,050	12,750	.7	9	36,800	2.0	2	89,000	4.9	11	125,800	6.9
1970	45	1,935,250	3,500	.2	9	47,850	2.5	1	30,000	1.6	10	77,850	4.0
1971	45	2,011,600	4,500	.2	10	39,000	1.9	3	111,000	5.5	13	150,000	7.5
10-Yr. Summary*		1,513,302			100	444,790	29.4	13	329,550	21.8	113	774,340	51.2
Compounded Annual Rate of Increase or (Decrease)							2.6			2.0			4.3

	Capacity Lost Through Total or Partial Refinery Shutdowns			Capacity Lost Through Consolidations			Other Declines in Capacity			Total Declines			Net Increase or (Decrease)		Ending Operating Capacity (Bbls/Day)
	No.	Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%	No.	Bbls/Day	%	Bbls/Day	%	
1962	0	0	0	0	0	0	2	6,500	.4	2	6,500	.4	10,450	.7	1,523,752
1963	0	0	0	0	0	0	4	12,752	.8	4	12,752	.8	61,988	4.1	1,585,740
1964	3	25,300	1.6	1	33,000	2.1	5	11,900	.8	9	70,200	4.4	4,821	.3	1,590,561
1965	0	0	0	1	1,000	.1	4	14,140	.9	5	15,140	1.0	17,659	1.1	1,608,220
1966	0	0	0	0	0	0	2	1,100	.1	2	1,100	.1	54,680	3.4	1,662,900
1967	1	2,000	.1	0	0	0	1	1,000	.1	2	3,000	.2	61,850	3.7	1,724,750
1968	1	1,250	.1	0	0	0	1	10,000	.6	2	11,250	.7	89,300	5.2	1,814,050
1969	0	0	0	0	0	0	3	4,600	.3	3	4,600	.3	121,200	6.7	1,935,250
1970	1	1,000	.1	0	0	0	1	500	0	2	1,500	.1	76,350	3.9	2,011,600
1971	2	9,300	.5	0	0	0	2	1,500	.1	4	10,800	.5	139,200	6.9	2,150,800
10-Yr. Summary*	8	38,850	3.6	2	34,000	2.2	25	63,992	4.2	35	136,842	9.0	637,498	42.0	2,150,800
Compounded Annual Rate of Increase or (Decrease)			.3			.2			.4			.85		3.6	

* 10-Year Summary percentages are based on 1962 beginning operating capacity.

Source: U.S. Bureau of Mines, "Petroleum Refineries in the United States," *Mineral Industries Survey*, published annually.

APPENDIX E
Foreign Refining Capacity Trends

FOREIGN REFINING CAPACITY TRENDS

The NPC non-Communist foreign energy/oil, requirements/supply and U.S. import projections provide an appropriate context in which to review foreign refining capacity trends--past, present and future. For purposes of assessing foreign refining capacity we will consider trends in three types of foreign refineries. These are classified according to principal function (resources, market and intermediate refineries) and are explained as follows:

- *Resource Refineries*: Refineries designed to convert crude to products mainly for export, and which are located proximate to foreign crude producing areas--mainly the Middle East and Venezuela
- *Market Refineries*: Refineries designed to supply specific market areas and located at or near large centers of consumption, such as Western Europe or Japan
- *Intermediate Refineries*: Swing or balance refineries built along the transportation route between several major crude supply sources and major markets. These refineries import all or most of their crude requirements and export large product volumes, such as refineries at Aden, Canary Islands, Singapore, Trinidad, Bahamas, Aruba, Curacao and the Virgin Islands.

DATA BASE AND ASSUMPTIONS

Specifically, the basis and the principal assumptions behind the data are as follows.

Data Base

To provide a consistent, continuous data base over the 1950-1972 period, the *Oil and Gas Journal's* annual "Worldwide Refining" tabulation was used for all non-Communist foreign refinery capacities as of January 1 of the indicated year. All capacities are reported in thousand barrels per stream day (MB/SD). A 95 percent operating factor was used to convert volumes to a stream day basis where necessary (see Table 56).

Capacities shown for 1975 are projected on a current plus announced basis: that is, they are based on the *Oil and Gas Journal* 1972 annual survey data plus all new capacity which is scheduled for completion before January 1, 1975, under construction or announced in the press as of late 1972. Thus, the 1975 capacity projection does not allow for any new capacity yet to be anounced or for modifications in present announcements, nor does it allow for additional capacity which may be needed over that shown in some areas.

TABLE 56

NON-COMMUNIST FOREIGN REFINING CAPACITY
(Start-of-Year)

	1950		1955		1960		1965		1970		1971		1972		1975	
	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%
Western Europe																
Resource Refineries	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Intermediate Refineries	151	18.4	369	15.7	597	15.0	1,158	15.2	2,007	14.2	2,251	14.3	2,460	14.8	2,568	11.6
Market Refineries	668	81.6	1,988	84.3	3,387	85.0	6,483	84.8	12,129	85.8	13,453	85.7	14,135	85.2	19,662	88.4
Total	819	100.0	2,357	100.0	3,984	100.0	7,641	100.0	14,136	100.0	15,704	100.0	16,595	100.0	22,230	100.0
Africa																
Resource Refineries	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Intermediate Refineries	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Market Refineries	39	100.0	68	100.0	116	100.0	502	100.0	779	100.0	853	100.0	902	100.0	1.232	100.0
Total	39	100.0	68	100.0	116	100.0	502	100.0	779	100.0	853	100.0	902	100.0	1,232	100.0
Middle East																
Resource Refineries	702	84.9	848	77.9	1,008	70.7	1,198	69.9	1,538	66.6	1,617	66.3	1,735	67.5	1,735	58.9
Intermediate Refineries	—	—	120	11.0	120	8.4	150	8.8	178	7.7	178	7.3	178	6.9	178	6.0
Market Refineries	125	15.1	121	11.1	297	20.9	365	21.3	592	25.7	645	26.4	658	25.6	1.033	35.1
Total	827	100.0	1,089	100.0	1,425	100.0	1,713	100.0	2,308	100.0	2,440	100.0	2,571	100.0	2,946	100.0
Far East																
Resource Refineries	71	27.3	131	27.5	156	13.8	156	5.6	173	3.5	173	3.0	273	4.3	326	3.7
Intermediate Refineries	—	—	—	—	—	—	—	—	100	2.1	285	4.9	285	4.5	958	11.0
Market Refineries	189	72.7	346	72.5	978	86.2	2,638	94.4	4.615	94.4	5,331	92.1	5,830	91.2	7.418	85.3
Total	260	100.0	477	100.0	1,134	100.0	2,794	100.0	4,888	100.0	5,789	100.0	6,388	100.0	8,702	100.0
Oceania																
Resource Refineries	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Intermediate Refineries	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Market Refineries	14	100.0	57	100.0	237	100.0	424	100.0	659	100.0	706	100.0	767	100.0	812	100.0
Total	14	100.0	57	100.0	237	100.0	424	100.0	659	100.0	706	100.0	767	100.0	812	100.0

TABLE 56 (CONT'D.)

NON-COMMUNIST FOREIGN REFINING CAPACITY
(Start-of-Year)

	1950		1955		1960		1965		1970		1971		1972		1975	
	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%
Caribbean																
Resource Refineries	135	14.9	516	38.8	874	44.0	1,075	42.3	1,279	37.7	1,313	35.2	1,341	33.4	1,652	34.6
Intermediate Refineries	660	72.5	750	56.3	921	46.4	1,130	44.5	1,621	47.8	1,910	51.1	2,103	52.4	2,522	52.8
Market Refineries	115	12.6	64	4.9	190	9.6	337	13.2	493	14.5	513	13.7	567	14.2	599	12.6
Total	910	100.0	1,330	100.0	1,985	100.0	2,542	100.0	3,393	100.0	3,736	100.0	4,011	100.0	4,773	100.0
Other Latin America																
Resource Refineries	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Intermediate Refineries	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Market Refineries	365	100.0	501	100.0	874	100.0	1,349	100.0	1,759	100.0	1,828	100.0	2,134	100.0	2,634	100.0
Total	365	100.0	501	100.0	874	100.0	1,349	100.0	1,759	100.0	1,828	100.0	2,134	100.0	2,634	100.0
Canada																
Resource Refineries	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Intermediate Refineries	–	–	–	–	–	–	–	–	–	–	–	–	193	10.5	298	14.7
Market Refineries	340	100.0	609	100.0	920	100.0	1,115	100.0	1,438	100.0	1,483	100.0	1,639	89.5	1,734	85.3
Total	340	100.0	609	100.0	920	100.0	1,115	100.0	1,438	100.0	1,483	100.0	1,832	100.0	2,032	100.0
Total Non-Communist Foreign																
Resource Refineries	908	25.4	1,495	23.0	2,038	19.1	2,429	13.4	2,990	10.2	3,103	9.5	3,349	9.5	3,713	8.2
Intermediate Refineries	811	22.7	1,239	19.1	1,638	15.3	2,438	13.5	3,906	13.3	4,624	14.2	5,219	14.8	6,524	14.4
Market Refineries	1,855	51.9	3,754	57.9	6,999	65.6	13,213	73.1	22,464	76.5	24,812	76.3	26,632	75.7	35,124	77.4
Total	3,574	100.0	6,488	100.0	10,675	100.0	18,080	100.0	29,360	100.0	32,539	100.0	35,200	100.0	45,361	100.0

SOURCE: *Oil & Gas Journal*, "Worldwide Refining Tabulation."

Data on refinery ownership was obtained from the press, industrial directories, annual reports, etc., giving equity ownership of refining companies and governments in each of the refineries. Changes in company and refinery ownership throughout the historical period were taken into account.

Working Assumptions

Consistent with the above definitions of resource, intermediate, and market refineries, each non-Communist foreign refinery existing on January 1, 1972, was assigned to one of the three categories. As explained below, a portion of mainland Europe's capacity is allocated to the intermediate class as required to supply Scandinavia. Each refinery was kept in its 1972 category throughout the historical period. The same groupings were maintained for the 1975 data as well, but new refineries were added to each of the three classes as appropriate.

The tables on refinery ownership (Tables 57 and 58) show the equity share of refinery capacity owned by "100 percent government owned companies." Companies which are partly government owned--such as British Petroleum (50 percent) and Companie Francaise des Petrols (35 percent)--are excluded from the "government owned" class.

Some of the specific assumptions involved are best covered in an area-by-area discussion:

- *Western Europe:* The Organization for Economic Cooperation and Development (OECD) definition of Western Europe (i.e., Greece and Turkey are included) is expanded to include Yugoslavia and the Canary Islands.

  The Western European "market" is defined as a single integral market (except for Scandinavia). Thus, essentially all of Europe's refineries are classified as market refineries, despite the large amount of trade in oil products between the European nations. The only refineries specifically included in the intermediate class are those on the islands of Sicily, Sardinia and the Canaries. In addition, however, the share of Europe's refineries required to supply products for export to the Scandinavian market was included in the intermediate class.

- *Caribbean:* The Caribbean area includes the Central American mainland south of Mexico, Antigua, Bahamas, Barbados, Columbia, Jamaica, Martinique, Netherland Antilles, Puerto Rico, Trinidad and Tobago, Venezuela and the Virgin Islands.

- *Canada:* Canada's "market" is treated as a whole, so that all of her refineries are classified as market refineries, with the exception of three new refineries in the northeast. These new refineries--Gulf (Nova Scotia), Golden Eagle

TABLE 57

NON-COMMUNIST FOREIGN REFINERY OWNERSHIP BY AREA
(Start-of-Year)

	1950		1955		1960		1965		1970		1971		1972		1975	
	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%
Western Europe																
7 International Majors	393	48.0	1,427	60.5	2,413	60.6	4,373	57.3	8,150	57.7	8,727	55.6	9,489	57.2	12,266	55.2
Memo: 5 U.S. International Majors	121	14.8	496	21.0	951	23.9	1,978	25.9	4,171	29.5	4,515	28.7	4,899	29.5	5,869	26.4
"New Majors" (U.S. Based Companies)	6	0.7	14	0.6	49	1.2	153	2.0	486	3.4	535	3.4	548	3.3	737	3.3
100% Government-Owned Companies	30	3.7	106	4.5	174	4.4	553	7.2	1,146	8.1	1,387	8.8	1,507	9.1	2,017	9.1
All Other Companies	390	47.6	810	34.4	1,348	33.8	2,562	33.5	4,354	30.8	5,055	32.2	5,051	30.4	7,210	32.4
Total	819	100.0	2,357	100.0	3,984	100.0	7,641	100.0	14,136	100.0	15,704	100.0	16,595	100.0	22,230	100.0
Africa																
7 International Majors	12	30.8	12	17.6	20	17.2	165	32.9	237	30.4	244	28.6	248	27.5	389	31.6
Memo: 5 U.S. International Majors	—	—	—	—	2	1.7	39	7.8	71	9.1	81	9.5	82	9.1	131	10.6
"New Majors" (U.S. Based Companies)	—	—	—	—	—	—	3	0.6	8	1.0	5	0.6	5	0.5	5	0.4
100% Government-Owned Companies	23	59.0	32	47.1	63	54.3	163	32.5	269	34.6	283	33.2	322	35.7	486	39.4
All Other Companies	4	10.2	24	35.3	33	28.5	171	34.0	265	34.0	321	37.6	327	36.3	352	28.6
Total	39	100.0	68	100.0	116	100.0	502	100.0	779	100.0	853	100.0	902	100.0	1,232	100.0
Middle East																
7 International Majors	662	80.1	913	83.8	1,175	82.5	1,286	75.1	1,525	66.1	1,603	65.7	1,702	66.2	1,714	58.2
Memo: 5 U.S. International Majors	437	52.8	545	50.0	685	48.1	736	43.0	920	39.9	990	40.6	1,069	41.6	1,074	36.5
"New Majors" (U.S. Based Companies)	—	—	30	2.8	80	5.6	160	9.3	194	8.4	194	8.0	194	7.5	194	6.6
100% Government-Owned Companies	2	0.2	40	3.7	51	3.6	111	6.5	272	11.8	279	11.4	284	11.1	502	17.0
All Other Companies	163	19.7	106	9.7	119	8.3	156	9.1	317	13.7	364	14.9	391	15.2	536	18.2
Total	827	100.0	1,089	100.0	1,425	100.0	1,713	100.0	2,308	100.0	2,440	100.0	2,571	100.0	2,946	100.0
Far East																
7 International Majors	183	70.4	319	66.9	522	46.0	1,064	38.1	1,473	30.1	1,723	29.8	1,839	28.8	2,661	30.6
Memo: 5 U.S. International Majors	64	24.6	119	24.9	219	19.3	564	20.2	967	19.8	1,086	18.8	1,167	18.3	1,844	21.2
"New Majors" (U.S. Based Companies)	4	1.5	8	1.7	30	2.7	82	2.9	143	2.9	163	2.8	163	2.6	270	3.1
100% Government-Owned Companies	—	—	3	0.6	5	0.4	67	2.4	535	11.0	629	10.9	908	14.2	1,004	11.5
All Other Companies	73	28.1	147	30.8	577	50.9	1,581	56.6	2,737	56.0	3,274	56.5	3,478	54.4	4,767	54.8
Total	260	100.0	477	100.0	1,134	100.0	2,794	100.0	4,888	100.0	5,789	100.0	6,388	100.0	8,702	100.0
Oceania																
7 International Majors	9	64.3	46	80.7	224	94.5	386	91.0	548	83.2	594	84.1	637	83.1	682	84.0
Memo: 5 U.S. International Majors	2	14.3	2	3.5	88	37.1	215	50.7	225	34.1	252	35.7	270	35.2	315	38.8
"New Majors" (U.S. Based Companies)	—	—	—	—	—	—	—	—	25	3.8	27	3.8	27	3.5	27	3.3

TABLE 57 (CONT'D.)

NON-COMMUNIST FOREIGN REFINERY OWNERSHIP BY AREA
(Start-of-Year)

	1950		1955		1960		1965		1970		1971		1972		1975	
	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%
Oceania (Cont'd.)																
100% Government-Owned Companies	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
All Other Companies	5	35.7	11	19.3	13	5.5	38	9.0	86	13.0	85	12.1	103	13.4	103	12.7
Total	14	100.0	57	100.0	237	100.0	424	100.0	659	100.0	706	100.0	767	100.0	812	100.0
Caribbean																
7 International Majors	841	92.4	1,254	94.3	1,824	91.9	2,190	86.2	2,724	80.3	2,867	76.7	2,953	73.6	3,347	70.1
Memo: 5 U.S. International Majors	530	58.2	834	62.7	1,212	61.1	1,588	62.5	1,874	55.2	2,014	53.9	2,072	51.7	2,350	49.2
"New Majors" (U.S. Based Companies)	–	–	38	2.8	108	5.4	194	7.6	432	12.7	640	17.1	785	19.6	1,016	21.3
100% Government-Owned Companies	23	2.5	37	2.8	48	2.4	139	5.5	187	5.5	190	5.1	231	5.8	352	7.4
All Other Companies	46	5.1	1	0.1	5	0.3	19	0.7	50	1.5	39	1.1	42	1.0	58	1.2
Total	910	100.0	1,330	100.0	1,985	100.0	2,542	100.0	3,393	100.0	3,736	100.0	4,011	100.0	4,773	100.0
Other Latin America																
7 International Majors	54	14.8	94	18.8	127	14.5	206	15.3	183	10.4	187	10.2	247	11.6	247	9.4
Memo: 5 U.S. International Majors	54	14.8	76	15.2	104	11.9	126	9.3	93	5.3	96	5.3	126	5.9	126	4.8
"New Majors" (U.S. Based Companies)	–	–	–	–	–	–	1	0.1	3	0.2	3	0.2	3	0.1	3	0.1
100% Government-Owned Companies	270	74.0	353	70.4	683	78.2	1,127	83.5	1,468	83.4	1,523	83.3	1,771	83.0	2,239	85.0
All Other Companies	41	11.2	54	10.8	64	7.3	15	1.1	105	6.0	115	6.3	113	5.3	145	5.5
Total	365	100.0	501	100.0	874	100.0	1,349	100.0	1,759	100.0	1,828	100.0	2,134	100.0	2,634	100.0
Canada																
7 International Majors	204	60.0	346	56.8	591	64.2	814	73.0	999	69.5	1,043	70.3	1,246	68.0	1,326	65.3
Memo: 5 U.S. International Majors	175	51.5	285	46.8	518	56.3	597	53.5	674	46.9	706	47.6	904	49.3	933	45.9
"New Majors" (U.S. Based Companies)	–	–	17	2.8	16	1.8	32	2.9	106	7.4	107	7.2	107	5.8	212	10.4
100% Government-Owned Companies	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
All Other Companies	136	40.0	246	40.4	313	34.0	269	24.1	333	23.1	333	22.5	479	26.2	494	24.3
Total	340	100.0	609	100.0	920	100.0	1,115	100.0	1,438	100.0	1,483	100.0	1,832	100.0	2,032	100.0
Total Non-Communist Foreign																
7 International Majors	2,358	66.0	4,411	68.0	6,896	64.6	10,484	58.0	15,839	53.9	16,988	52.2	18,361	52.2	22,632	49.9
Memo: 5 U.S. International Majors	1,383	38.7	2,357	36.3	3,779	35.4	5,843	32.3	8,995	30.6	9,740	29.9	10,589	30.1	12,642	27.9
"New Majors" (U.S. Based Companies)	10	0.3	107	1.6	283	2.6	625	3.5	1,397	4.8	1,674	5.1	1,832	5.2	2,464	5.4
100% Government-Owned Companies	348	9.7	571	8.8	1,024	9.6	2,160	11.9	3,877	13.2	4,291	13.2	5,023	14.3	6,600	14.6
All Other Companies	858	24.0	1,399	21.6	2,472	23.2	4,811	26.6	8,247	28.1	9,586	29.5	9,984	28.3	13,665	30.1
Total	3,574	100.0	6,488	100.0	10,675	100.0	18,080	100.0	29,360	100.0	32,539	100.0	35,200	100.0	45,361	100.0

SOURCE: Based on *Oil and Gas Journal* capacities.

TABLE 58

NON-COMMUNIST FOREIGN REFINERY OWNERSHIP BY REFINERY TYPE
(Start-of-Year)

	1950		1955		1960		1965		1970		1971		1972		1975	
	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%	MB/SD	%
Resource Refineries																
7 International Majors	903	99.4	1,384	92.6	1,867	91.6	2,234	92.0	2,542	85.0	2,640	85.1	2,764	82.5	2,954	79.6
Memo: 5 U.S. International Majors	494	54.4	825	55.2	1,123	55.1	1,415	58.3	1,724	57.7	1,822	58.7	1,904	56.9	2,094	56.4
"New Majors" (U.S. Based Companies)	–	–	68	4.5	69	3.4	152	6.2	191	6.4	191	6.2	194	5.8	194	5.2
100% Government-Owned Companies	–	–	–	–	–	–	–	–	110	3.7	110	3.5	210	6.3	384	10.3
All Other Companies	5	0.6	43	2.9	102	5.0	43	1.8	147	4.9	162	5.2	181	5.4	181	4.9
Total	908	100.0	1,495	100.0	2,038	100.0	2,429	100.0	2,990	100.0	3,103	100.0	3,349	100.0	3,713	100.0
Intermediate Refineries																
7 International Majors	752	92.7	1,048	84.6	1,239	75.6	1,617	66.3	2,175	55.7	2,506	54.2	2,624	50.3	3,274	50.2
Memo: 5 U.S. International Majors	479	59.1	582	47.0	700	42.7	1,001	41.1	1,344	34.4	1,499	32.4	1,600	30.7	2,068	31.7
"New Majors" (U.S. Based Companies)	1	0.1	2	0.2	75	4.6	127	5.2	359	9.2	548	11.9	738	14.1	1,118	17.1
100% Government-Owned Companies	5	0.6	13	1.0	19	1.2	96	4.0	109	2.8	113	2.4	125	2.4	121	1.9
All Other Companies	53	6.6	176	14.2	305	18.6	598	24.5	1,263	32.3	1,457	31.5	1,732	33.2	2,011	30.8
Total	811	100.0	1,239	100.0	1,638	100.0	2,438	100.0	3,906	100.0	4,624	100.0	5,219	100.0	6,524	100.0
Market Refineries																
7 International Majors	703	37.9	1,979	52.7	3,790	54.1	6,633	50.2	11,122	49.5	11,842	47.7	12,973	48.7	16,404	46.7
Memo: 5 U.S. International Majors	410	22.1	950	25.3	1,956	27.9	3,427	25.9	5,927	26.4	6,419	25.9	7,085	26.6	8,773	25.0
"New Majors" (U.S. Based Companies)	9	0.5	37	1.0	139	2.0	346	2.6	847	3.8	935	3.8	900	3.4	1,152	3.3
100% Government-Owned Companies	343	18.5	558	14.9	1,005	14.4	2,064	15.6	3,658	16.3	4,068	16.4	4,688	17.6	6,095	17.3
All Other Companies	800	43.1	1,180	31.4	2,065	29.5	4,170	31.6	6,837	30.4	7,967	32.1	8,071	30.3	11,473	32.7
Total	1,855	100.0	3,754	100.0	6,999	100.0	13,213	100.0	22,464	100.0	24,812	100.0	26,632	100.0	35,124	100.0
Total Non-Communist Foreign																
7 International Majors	2,358	66.0	4,411	68.0	6,896	64.6	10,484	58.0	15,839	53.9	16,988	52.2	18,361	52.2	22,632	49.9
Memo: 5 U.S. International Majors	1,383	38.7	2,357	36.3	3,779	35.4	5,843	32.3	8,995	30.6	9,740	29.9	10,589	30.1	12,935	28.5
"New Majors" (U.S. Based Companies)	10	0.3	107	1.6	283	2.6	625	3.5	1,397	4.8	1,674	5.1	1,832	5.2	2,464	5.4
100% Government-Owned Companies	348	9.7	571	8.8	1,024	9.6	2,160	11.9	3,877	13.2	4,291	13.2	5,023	14.3	6,600	14.6
All Other Companies	858	24.0	1,399	21.6	2,472	23.2	4,811	26.6	8,247	28.1	9,586	29.5	9,984	28.3	13,665	30.1
Total	3,574	100.0	6,488	100.0	10,675	100.0	18,080	100.0	29,360	100.0	32,539	100.0	35,200	100.0	45,361	100.0

SOURCE: Based on *Oil and Gas Journal* capacities.

(Quebec) and Newfoundland Refining (under construction in Newfoundland)--are scheduled to refine imported crude and reportedly will ship most of their product output to the U.S. East Coast. The total capacity of these three refineries is included in the intermediate category.

CAPACITY TRENDS IN REFINERY TYPES AND OWNERSHIP

Capacity Trends in Refinery Types

Total refining capacity in the non-Communist world has increased from 3.6 MMB/SD in 1950 to 35.2 MMB/SD in 1972 (see Table 56).

Market refineries have increased significantly in their share of total foreign refining capacity over the past 20 years, up from about 1.9 MMB/SD, or about 52 percent of total capacity in 1950, to over 26 MMB/SD, or almost 76 percent in 1972.

Resource refineries have been declining in relative importance over the past 20 years, although capacity has increased in absolute terms from 0.9 MMB/SD in 1950 to 3.3 MMB/SD in 1972. Resource refineries share of total foreign refining has dropped from over 25 percent in 1950 to 9.5 percent in 1972.

Intermediate refinery capacity was 0.8 MMB/SD, or 23 percent of the total, in 1950. Although their capacity has grown steadily, their share of the total dropped until 1970 (3.9 MMB/SD, 13 percent of the total), when the trend reversed. Intermediate refineries are now on the upswing, amounting to 5.2 MMB/SD, or almost 15 percent of the total in 1972.

Ownership Trends

The International Majors share of foreign capacity has declined from almost 66 percent in 1950 to about 52 percent in 1972. In the meantime, government owned companies and all other companies have increased their share significantly. The "New Majors" (U.S. based companies) have carved out a 5 percent share of foreign refining capacity by 1972, starting from essentially nothing in 1950.

The International Majors have owned nearly all of the resource refinery capacity, but their share has declined from 99 percent in 1950 to under 83 percent in 1972 (Table 58). The Majors ownership of intermediate refineries has declined sharply, from 93 percent in 1950 to 50 percent in 1972. The New Majors and other nongovernment companies have accounted for most of the difference. Government company ownership of both resource and intermediate refineries has been much lower than the government share of market refineries. The International Majors increased their share of market refineries from 38 percent in 1950 to 54 percent in 1960, but have slowly declined in importance since then (49 percent in 1972).

CAPACITY TRENDS IN PROCESSING

Downstream Processing Capacity Trends

Table 59 shows trends in the development of downstream processing capacity in the non-Communist foreign area over the past 20 years. Total cracking capacity has declined from 22 percent of total refining capacity in 1960 to 13 percent in 1972. Total reforming capacity has remained essentially constant as a percent of crude capacity over the same period (10 percent in 1960, 11 percent in 1972).

These trends reflect the fact that foreign refiners operate primarily to produce distillate and residual fuel oils. Rapid industrialization in these areas over the past 20 years, combined with the substitution of oil for coal in many areas, has increased the requirement for these fuels as compared to the lighter fractions used in transportation, etc. Even Canada shows a decline in cracking capacity as a percentage of crude capacity, reflecting the growing production of heavy fuel oils in eastern Canadian refineries for industrial and utility use in the United States and Canada.

The primary emphasis in foreign refinery downstream processing trends has been on product quality improvement rather than on the alteration of the basic product slate. These trends are expected to continue. The recent appearance of fuel oil desulfurization facilities in foreign refineries, discussed in the following section, is an important example of this "quality improvement" type of downstream processing.

Fuel Oil Desulfurization

Fuel oil desulfurization capacity, nonexistent until 1967, has increased at an average rate of 100 MB/SD per year since 1968 both in Japan and in the Caribbean. The outlook for the 1970's, based on the estimates in Table 60, is for construction rates several times higher than this in both areas, with particular emphasis likely around mid-decade. Construction plans already on the books amount to about 350 MB/SD in each area by 1975, and the supply/demand balance indicates that even more new capacity will be required by that date. Western Europe, now some 5 years behind the United States in sulfur emission regulations, will need to build fuel oil desulfurization capacity at a similar rate starting after 1975. This, of course, depends on the disposition of low-sulfur crudes to the various market areas.

Table 60 shows the outlook for 1975 and 1980, emphasizing the growing gap (particularly in the Atlantic area) between low-sulfur fuel oil requirements and low-sulfur crude availability. The principal assumptions behind the calculations are as follows:

- The estimate of low-sulfur fuel oil demand in the U.S. Districts I through IV is based on our overall appraisal of U.S. energy and fuel oil demand and our most current

TABLE 59

NON-COMMUNIST FOREIGN REFINING: DOWNSTREAM PROCESSING
(Start-of-Year Feed Capacities)

	1950*		1955†		1960		1965		1970		1971		1972	
	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total
W. Europe - Total Refining Capacity	819		2,318		3,984		7,641		14,136		15,704		16,595	
Thermal Cracking and Visbreaking			301	13.0	115	2.9	407	5.3	432	3.1	443	2.8	502	3.0
Catalytic Cracking			306	13.2	471	11.8	613	8.0	777	5.5	894	5.7	930	5.6
Hydrocracking			–	–	–	–	7	0.1	35	0.2	40	0.2	55	0.3
Coking			–	–	–	–	20	0.3	62	0.4	89	0.6	112	0.7
Total Cracking and Coking	142	17.3	607	26.2	586	14.7	1,047	13.7	1,306	9.2	1,466	9.3	1,599	9.6
Catalytic Reforming			43	1.9	374	9.4	995	13.0	1,846	13.0	1,948	12.4	2,118	12.8
Thermal Reforming			–	–	200	5.0	198	2.6	111	0.8	109	0.7	87	0.5
Total Reforming			43	1.9	574	14.4	1,193	15.6	1,957	13.8	2,057	13.1	2,205	13.3
Fuel Oil Desulfurization	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Africa - Total Refining Capacity	39		68		116		502		779		853		902	
Thermal Cracking and Visbreaking			8	11.8	3	2.6	7	1.4	27	3.5	28	3.3	23	2.5
Catalytic Cracking			6	8.8	13	11.2	30	6.0	42	5.4	63	7.4	63	7.0
Hydrocracking			–	–	–	–	–	–	–	–	10	1.1	10	1.1
Coking			–	–	–	–	6	1.2	–	–	–	–	–	–
Total Cracking and Coking	7	17.9	14	20.6	16	13.8	43	8.6	69	8.9	101	11.8	96	10.6
Catalytic Reforming			–	–	5	4.3	87	17.3	126	16.2	148	17.3	139	15.4
Thermal Reforming			–	–	7	6.0	7	1.4	4	0.5	4	0.5	4	0.4
Total Reforming			–	–	12	10.3	94	18.7	130	16.7	152	17.8	143	15.8
Fuel Oil Desulfurization	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Middle East - Total Refining Capacity	827		1,089		1,425		1,713		2,308		2,440		2,571	
Thermal Cracking and Visbreaking			194	17.8	51	3.6	62	3.6	70	3.0	77	3.2	92	3.6
Catalytic Cracking			58	5.3	62	4.3	68	4.0	73	3.2	73	3.0	74	2.9
Hydrocracking			–	–	–	–	–	–	62	2.7	62	2.5	72	2.8
Coking			–	–	–	–	–	–	–	–	20	0.8	20	0.7
Total Cracking and Coking	208	25.2	252	23.1	113	7,9	130	7.6	205	8.9	232	9.5	258	10.0
Catalytic Reforming			26	2.4	48	3.4	88	5.1	131	5.7	128	5.2	130	5.1
Thermal Reforming			–	–	127	8.9	82	4.8	72	3.1	77	3.2	72	2.8
Total Reforming			26	2.4	175	12.3	170	9.9	203	8.8	205	8.4	202	7.9
Fuel Oil Desulfurization	–	–	–	–	–	–	–	–	–	–	–	–	–	–

TABLE 59 (CONT'D.)

NON-COMMUNIST FOREIGN REFINING: DOWNSTREAM PROCESSING
(Start-of-Year Feed Capacities)

	1950*		1955†		1960		1965		1970		1971		1972	
	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total
Far East - Total Refining Capacity	260		477		1,134		2,794		4,888		5,789		6,388	
Thermal Cracking and Visbreaking			74	15.5	60	5.3	49	1.7	103	2.1	117	2.0	103	1.6
Catalytic Cracking			14	2.9	96	8.4	161	5.8	210	4.3	264	4.6	339	5.3
Hydrocracking			–	–	–	–	–	–	10	0.2	12	0.2	12	0.2
Coking			–	–	2	0.2	8	0.3	33	0.7	33	0.6	33	0.5
Total Cracking and Coking	62	23.8	88	18.4	158	13.9	218	7.8	356	7.3	426	7.4	487	7.6
Catalytic Reforming			16	3.4	35	3.1	207	7.4	435	8.9	476	8.2	522	8.2
Thermal Reforming			–	–	19	1.7	15	0.5	15	0.3	15	0.3	16	0.2
Total Reforming			16	3.4	54	4.8	222	7.9	450	9.2	491	8.5	538	8.4
Fuel Oil Desulfurization	–	–	–	–	–	–	–	–	274	5.6	386	6.7	469	7.3
Oceania - Total Refining Capacity	14		57		237		424		659		706		767	
Thermal Cracking and Visbreaking			–	–	–	–	–	–	–	–	–	–	–	–
Catalytic Cracking			–	–	76	32.1	133	31.4	166	25.2	157	22.2	154	20.1
Hydrocracking			–	–	–	–	–	–	4	0.6	4	0.6	4	0.5
Coking			–	–	–	–	–	–	–	–	–	–	–	–
Total Cracking and Coking	–	–	–	–	76	32.1	133	31.4	170	25.8	161	22.8	158	20.6
Catalytic Reforming			–	–	21	8.9	86	20.3	143	21.7	162	22.9	164	21.4
Thermal Reforming			–	–	–	–	–	–	–	–	–	–	–	–
Total Reforming			–	–	21	8.9	86	20.3	143	21.7	162	22.9	164	21.4
Fuel Oil Desulfurization	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Caribbean - Total Refining Capacity	910		1,330		1,985		2,542		3,393		3,736		4,011	
Thermal Cracking and Visbreaking			532	40.0	535	26.9	603	23.7	614	18.1	595	15.9	593	14.8
Catalytic Cracking			74	5.6	283	14.3	261	10.3	291	8.6	287	7.7	282	7.0
Hydrocracking			–	–	–	–	–	–	–	–	–	–	–	–
Coking			–	–	–	–	–	–	–	–	–	–	–	–
Total Cracking and Coking	299	32.9	606	45.6	818	41.2	864	34.0	905	26.7	882	23.6	875	21.8
Catalytic Reforming	–		–	–	38	1.9	94	3.7	143	4.2	211	5.6	206	5.1
Thermal Reforming			–	–	29	1.5	28	1.1	7	0.2	7	0.2	7	0.2
Total Reforming			–	–	67	3.4	122	4.8	150	4.4	218	5.8	213	5.3
Fuel Oil Desulfurization	–	–	–	–	–	–	–	–	30	0.9	260	7.0	360	9.0

TABLE 59 (CONT'D.)

NON-COMMUNIST FOREIGN REFINING: DOWNSTREAM PROCESSING
(Start-of-Year Feed Capacities)

	1950*		1955†		1960		1965		1970		1971		1972	
	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total	MB/SD	% of Total
Other Latin America–														
Total Refining Capacity	365		501		874		1,349		1,759		1,828		2,134	
Thermal Cracking and Visbreaking			125	24.9	194	22.2	185	13.7	148	8.4	144	7.9	144	6.7
Catalytic Cracking			20	4.0	90	10.3	253	18.7	244	13.9	297	16.2	351	16.5
Hydrocracking			–	–	–	–	–	–	–	–	–	–	21	1.0
Coking			–	–	–	–	1	0.1	55	3.1	55	3.0	67	3.1
Total Cracking and Coking	104	28.5	145	28.9	284	32.5	439	32.5	447	25.4	496	27.1	583	27.3
Catalytic Reforming			–	–	–	–	52	3.9	115	6.5	116	6.4	133	6.2
Thermal Reforming			–	–	7	0.8	11	0.8	15	0.9	15	0.8	4	0.2
Total Reforming			–	–	7	0.8	63	4.7	130	7.4	131	7.2	137	6.4
Fuel Oil Desulfurization	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Canada - Total Refining Capacity	340		609		920		1,115		1,438		1,483		1,832	
Thermal Cracking and Visbreaking			172	28.2	52	5.7	57	5.1	34	2.4	34	2.3	34	1.9
Catalytic Cracking			212	34.8	281	30.5	355	31.8	394	27.4	390	26.3	427	23.3
Hydrocracking			–	–	–	–	–	–	6	0.4	24	1.6	24	1.3
Coking			–	–	13	1.4	13	1.2	14	1.0	14	0.9	17	0.9
Total Cracking and Coking	180	52.9	384	63.0	346	37.6	425	38.1	448	31.2	462	31.1	502	27.4
Catalytic Reforming			12	2.0	151	16.4	192	17.2	234	16.3	248	16.7	290	15.8
Thermal Reforming			–	–	–	–	–	–	–	–	–	–	–	–
Total Reforming			12	2.0	151	16.4	192	17.2	234	16.3	248	16.7	290	15.8
Fuel Oil Desulfurization	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total Non-Communist Foreign–														
Total Refining Capacity	3,574		6,449		10,675		18,080		29,360		32,539		35,200	
Thermal Cracking and Visbreaking			1,406	21.8	1,010	9.5	1,370	7.6	1,428	4.9	1,438	4.4	1,491	4.2
Catalytic Cracking			690	10.7	1,372	12.9	1,874	10.4	2,197	7.5	2,425	7.5	2,620	7.4
Hydrocracking			–	–	–	–	7	–	117	0.4	152	0.5	198	0.6
Coking			–	–	15	0.1	48	0.3	164	0.5	211	0.6	249	0.7
Total Cracking and Coking	1,002	28.0	2,096	32.5	2,397	22.5	3,299	18.3	3,906	13.3	4,226	13.0	4,558	12.9
Catalytic Reforming			97	1.5	672	6.3	1,801	10.0	3,173	10.8	3,437	10.6	3,702	10.5
Thermal Reforming			–	–	389	3.6	341	1.9	224	0.8	227	0.7	190	0.5
Total Reforming			97	1.5	1,061	9.9	2,142	11.9	3,397	11.6	3,664	11.3	3,892	11.0
Fuel Oil Desulfurization	–	–	–	–	–	–	–	–	304	1.0	646	2.0	829	2.4

* 1950 data does not provide detail on types of processes. Number shown under "Total Cracking and Coking" includes Thermal Cracking, Catalytic Cracking, Visbreaking, Coking and Thermal Reforming.

† Number shown under "Thermal Cracking and Visbreaking" in 1955 includes Coking and Thermal Reforming.

SOURCE: Based on *Oil and Gas Journal* capacities.

TABLE 60

LOW-SULFUR FUEL OIL ASSESSMENT – 1975 AND 1980
(MB/SD)

ATLANTIC AREA

	1975	1980
Low-Sulfur Crude Production and Disposition		
Production		
Africa	5,275	9,200
North Sea	750	2,000
Latin America	600	1,000
Total	8,625	12,200
Disposition		
Europe	5,925	7,350
U.S. Districts I-IV/Canada	740	1,650
Caribbean	950	1,600
Other Areas and Inventory	1,010	1,600
Total	8,625	12,200
Low-Sulfur Fuel Oil Supply/Demand Balance		
Western Europe		
Low-Sulfur Fuel Oil Consumption (1% S or less)	1,420	4,500
Potential Supply from Low-Sulfur Crude	2,590	3,620
30% Potential Supply Unavailable*	(780)	(1,090)
Net Potential Supply	1,810	2,530
Supply Required from Desulfurization (Potential Export Available for U.S.)	(390)	1,970†
U.S. Districts I - IV		
Low-Sulfur Fuel Oil Consumption (1% S or less)	2,810	3,790
Potential Supply from Low-Sulfur Crude	1,290	1,480
Supply Required from Desulfurization	1,520	2,310
Memo: U.S. and Caribbean Desulfurization Feed Capacity Required for Above Supply‡	1,590	2,530
Capacity On-Stream and Announced§	760	760
Unannounced New Capacity Required	830	1,770

FAR EAST

	1975	1980
Low-Sulfur Crude Production and Disposition		
Production		
Brunei/Malaysia	225	300
Indonesia	1,615	2,300
Total	1,840	2,600
Disposition		
Japan	1,000	1,650
U.S. District V	200	200
Other S.E. Asia & Inventory	640	750
Total	1,840	2,600
Low-Sulfur Crude from Atlantic Area to Far East	330	700
Total Low-Sulfur Crude Available for Far East	2,170	3,300
Low-Sulfur Fuel Oil Supply/Demand Balance		
Japan		
Regulated Onshore Fuel Oil Consumption (Pool Wt. % S)	2,545(0.7)	4,000(0.3)
Potential Supply from Low-Sulfur Crude	1,210	1,650
Low-Sulfur Fuel Oil Imports	325	450
Adjustment for Stack Gas Treating	100	300
Supply Required from Desulfurization	910	1,600
Memo: Desulfurization Feed Capacity Required for Above Supply, MB/SD‖	1,120	1,975
Capacity On-Stream and Announced	803	803
Unannounced New Capacity Required	317	1,172
Memo: Low-Sulfur Crude Burned Directly by Utilities	260	480

Memo: Foreign Fuel Oil Desulfurization Capacity (January 1)

	1968	1969	1970	1971	1972	(Announced) 1975
Western Europe	—	—	—	—	—	3
Caribbean	—	30	30	260	360	700
Japan	40	88	274	386	469	803
Total Foreign	40	118	304	646	829	1,506

*Potential low-sulfur fuel oil not available due to use as cracking feedstock, failure to segregate from high-sulfur crude use in markets where not required by law, etc.

†Maximum requirement; "potential supply unavailable" may be considerably lower than 30 percent by 1980.

‡Based on 90 percent operating factor and 90 percent fuel oil yield; allowance is made for blending VGO desulfurizer output with high-sulfur material to a 1 percent sulfur fuel oil.

§Includes 60 MB/SD unit announced by Supermarine Inc., New Jersey.

‖ Based on 90 percent operating factor and 90 percent fuel oil yield.

assumption of the likely impact of EPA regulation limits which will be in effect in 1975 and 1980 as a result of the 1970 Clean Air Act provisions.

- The estimate of low-sulfur fuel oil demand in Europe is based on our overall appraisal of European energy and, specifically, fuel oil demand. (Our estimates for total European oil demand correspond to the "high" end of the range agreed upon by the NPC.) It takes into account current air pollution regulations and our best present estimate of the development of new regulations through 1975. For 1980 we have assumed that total SO_2 emissions from fuel oil burning will be limited to a level no higher than in 1975.

- Low-sulfur fuel oil demand estimates for the United States and Europe do *not* account for stack gas treatment on oil-burning installations which, later in the decade, may prove economical for large consumer installations enabling them to burn high-sulfur fuel oil. Allowance is made, however, for stack gas sulfur removal from coal-burning installations later in the decade. U.S. low-sulfur fuel oil demand takes into account expected production of pipeline-quality gas by gasification, part of which will be competitive with low-sulfur fuel oil. No production of low BTU gas from oil or coal is assumed; if such a process proves economical, it could have an impact on low-sulfur fuel oil demand by 1980. Direct burning of low-sulfur crude oils and of light distillate fractions, such as naphtha, is expected to be comparatively small.

- The European balance allows for "potential supply unavailable" (from low-sulfur crude) for the low-sulfur fuel oil pool, due to use as cracking feedstock, failure to segregate from high-sulfur crude use in markets where not required by law, etc. The European refiners' "potential supply unavailable" is assumed to be 30 percent of total potential supply. Before 1975, the percentage unavailable because of nonsegregation undoubtedly is higher than 30 percent. However, by 1980, with low-sulfur fuel oil supply tight, the unavailable volume is likely to approach zero percent.

- The estimate of low-sulfur fuel oil demand in Japan is based on our overall appraisal of Japanese energy requirements. It takes into account direct crude burning, naphtha burning and significant commercialization of stack gas treatment on oil-burning installations. The Japanese now have operating or under construction 25 different pilot or semi-commercial stack gas treating plants representing 13 different processes. The competitive economics of stack gas treatment *versus* desulfurization have yet to be proved; the outcome will have a direct bearing on the desulfurization requirements estimated in Table 60.

- The allocation of desulfurization capacity to the various areas is arbitrary, since the inter-area flows of low-sulfur crude and fuel oil will depend on the specific logistic/economic situations of individual refiners. The Japanese balance allows for moderate imports of low-sulfur fuel oil produced from Asian low-sulfur crudes in the resource refineries of Indonesia and intermediate refineries, such as those in Singapore. However, no allowance is made for desulfurization of Persian Gulf crudes in the Middle East's resource refineries or in Asia's intermediate refineries.

Due to the assumptions noted above, the 2 MMB/SD of desulfurization capacity indicated for Europe in 1980 should be considered a maximum requirement. For example, if the "potential supply unavailable" were 10 percent instead of 30 percent, Europe's required desulfurization capacity in 1980 would be 1.2 MMB/SD instead of 2 MMB/SD. The estimates for the United States/Caribbean area and Japan are on firmer ground, but are quite susceptible to the assumptions relative to stack gas treatment and direct crude burning. On balance, considering the current state of technology for sulfur removal from stack gas, the outlook over at least the next 3 to 5 years is for accelerating growth of fuel oil desulfurization capacity in both Japan and the United States/Caribbean area.

THE OUTLOOK

The data on refinery capacity additions suggests that recent trends will continue. That is, market and intermediate refineries will continue to increase their share of total foreign refining capacity, and resource refineries' share of the total will continue to decline. Strong growth in intermediate refining capacity (beyond that shown by the data) will be encouraged by refinery siting problems and environmentalist concerns in the United States and Japan. The next few years will see Singapore become one of the large intermediate refining centers, with almost 500 MB/SD of new capacity planned between now and 1975. Other Asian areas, such as Okinawa and Taiwan, are also likely to develop as important intermediate refining sites.

The scheduled growth of intermediate refining capacity in the Caribbean and in eastern Canada is supported by the need to supply the United States with increasing volumes of low-sulfur fuel oil and bonded products and by the fact that U.S. refining capacity growth has failed to keep pace with demand. Further future growth of intermediate refining capacity to provide products for import into the United States will be, of course, heavily contingent on whether U.S. import controls are modified to stimulate the expansion of U.S. refining capacity.

Although the share of resource refineries is indicated to continue to decline, several factors may serve to counteract this trend. With the limited world supply of low-sulfur crudes, the African nations, Indonesia, Ecuador, etc., will be able to command premium prices for it. Rather than accept poorer prices for high-sulfur crudes, the Mid-East countries (with or without oil company participation) have a strong incentive to desulfurize their crude before marketing it. These countries have land, cheap natural gas, capital funds, a desire for downstreaming, etc. In addition, Japan is known to be looking to both the Middle East and Indonesia to expand their resource refinery capacities to supply Japan with oil products and ease her refinery siting problems.

Refinery ownership trends are also expected to continue, with the International Majors share declining and the government owned and other companies share increasing. The overall outlook for refining may be contingent on the outcome of negotiations now under way between the producing country governments and the oil companies.

APPENDIX F
Review of Sulfur Removal Regulations and Technology

TABLE 61

1975 REGULATIONS APPLICABLE TO FUEL BURNING SOURCES — ALLOWABLE EMISSIONS LBS $SO_2/10^6$ BTU

	FUEL LIMITATION %S (LBS. $S/10^6$ BTU)		HEAT INPUT (MILLION BTU/HR)								REMARKS
	OIL	COAL	≤10	<50	100	<250	>250	1000	>2000	ALL	
ALABAMA										1.2	FOR NEW SOURCES ONLY.
CLASS I COUNTY										1.2	CLASS I CO.: 50% OR LESS OF THE COUNTY POPULATION RESIDES IN A NON-URBAN PLACE, AS DEFINED BY THE U.S. DEPT. OF COMMERCE CENSUS BUREAU FOR 1970 OR A SECONDARY NATIONAL AMBIENT AIR QUALITY STANDARD IS BEING EXCEEDED BASED ON 1971 AIR QUALITY MEASUREMENTS.
CLASS II COUNTY										1.5	CLASS II CO.: MORE THAN 50% OF ALL COUNTY POPULATION RESIDES IN A NON-URBAN PLACE, AND NO SECONDARY NATIONAL AMBIENT AIR QUALITY STANDARD IS BEING EXCEEDED BASED ON 1971 AIR QUALITY MEASUREMENTS.
ALASKA										1.0	
ARIZONA											NOT TO CAUSE GROUND LEVEL CONCENTRATIONS TO EXCEED THEIR LIMITATIONS.
MARICOPA COUNTY											SAME AS STATE REGULATIONS.
PIMA COUNTY											SAME AS STATE REGULATIONS.
ARKANSAS											NOT TO CAUSE GROUND LEVEL CONCENTRATIONS TO EXCEED THEIR LIMITATIONS.
CALIFORNIA											EACH OF THE 50 COUNTIES IN CALIFORNIA HAS ITS OWN REGULATIONS.
COLORADO										0.3	THE STATE OF COLORADO REGULATION COVERS THE METROPOLITAN DENVER AQCR. THIS LIMITATION APPLIES AFTER JANUARY 1, 1975, BUT UNTIL THEN THE REGULATION IS 1.0 LBS $SO_2/10^6$ BTU.
CONNECTICUT	0.5	0.5								0.55	AFTER APRIL 1, 1973
DELAWARE											STATE REGULATION: SO_2 EMISSIONS SHALL BE CONTROLLED TO MEET THE AMBIENT AIR QUALITY REQUIREMENTS.
NEW CASTLE CO.	0.3	0.3									AFTER JANUARY 1, 1975 IF NATIONAL SECONDARY AMBIENT AIR QUALITY STANDARD HAS BEEN EXCEEDED IN METROPOLITAN PHILADELPHIA AQCR. BETWEEN JULY 1, 1973 AND OCTOBER 1, 1974. OTHERWISE: DISTILLATE OIL 0.3% AFTER JANUARY 1, 1972; ALL OTHER FUEL 1.0% AFTER JANUARY 1, 1973

TABLE 61 (CONT'D.)

1975 REGULATIONS APPLICABLE TO FUEL BURNING SOURCES – ALLOWABLE EMISSIONS LBS $SO_2/10^6$ BTU

	FUEL LIMITATION % S (LBS S/10^6 BTU)		HEAT INPUT (MILLION BTU/HR)								REMARKS
	OIL	COAL	≤10	<50	100	<250	>250	1000	>2000	ALL	
KENT & SUSSEX CO.	0.3 DISTILLATE										EMISSION RATE SHALL BE DETERMINED BY ACCEPTABLE ATMOSPHERIC DISPERSION EQUATIONS IN ORDER TO MEET AIR QUALITY STANDARDS.
DISTRICT OF COLUMBIA	0.5	0.5									AFTER JULY 1, 1975 - UNTIL THEN 1% S FOR COAL; FOR OIL 1% S UNTIL JULY 1, 1973 AND 0.8% S UNTIL JULY 1, 1975.
FLORIDA							0.8 OIL 1.2 COAL				FOR NEW SOURCES ONLY. REGULATIONS FOR EXISTING SOURCES: 1.1 LBS $SO_2/10^6$ BTU FOR OIL | FOR >250 MILLION 1.5 LBS $SO_2/10^6$ BTU FOR COAL | BTU
GEORGIA							0.8 OIL 1.2 COAL				FOR NEW SOURCES ONLY; FOR EXISTING SOURCES LIMITATION IS A FUNCTION OF STACK HEIGHT, HEAT INPUT, LOCATION, FUEL USED. 2.5% S FOR COAL AND OIL FOR FUEL BURNING SOURCES <100 MILLION BTU/HR OF HEAT INPUT; 3.0% S FOR COAL AND OIL FOR FUEL BURNING SOURCES >100 MILLION BTU OF HEAT INPUT
HAWAII	0.5										AFTER JUNE 1, 1974 FOR FUEL BURNING SOURCES >250 MILLION BTU/HR AND 2.0% S FOR FUEL BURNING SOURCES <250 MILLION BTU/HR.
IDAHO	0.3 RESIDUAL 0.2 DISTILLATE	0.7									THIS REGULATION IS BEING DELETED, AND NEW % S LIMITATIONS WILL BE SET BY THE STATE WITHIN 1 YEAR OF APPROVAL OF THE PIAN.
ILLINOIS							1.2 COAL 0.8 RESID 0.3 DIST.				FOR NEW SOURCES ONLY; FOR EXISTING SOURCES AT ALL HEAT INPUTS: 1.0 LBS $SO_2/10^6$ BTU FOR RESIDUAL OIL 0.3 LBS $SO_2/10^6$ BTU FOR DISTILLATE OIL 1.8 LBS $SO_2/10^6$ BTU FOR COAL. } FOR CHICAGO, ST. LOUIS, AND BURLINGTON AQCR's
GRANITE CITY											SO_2 EMISSIONS MAY NOT CAUSE THE AMBIENT AIR TO EXCEED ITS LIMITATIONS AT ANY OCCUPIED PLACE BEYOND THE PREMISES ON WHICH THE SOURCE IS LOCATED.
COOK COUNTY	1.0	1.0									
INDIANA											NOT IN EXCESS OF 6.0 LBS $SO_2/10^6$ BTU OR $E_m=17Q^{-0.33}$ WHICHEVER IS LESS. IN NO CASE WILL STANDARD OF LESS THAN 1.2 LBS $SO_2/10^6$ BTU BE REQUIRED.
LAKE COUNTY											NOT TO CAUSE GROUND LEVEL CONCENTRATIONS TO EXCEED THEIR LIMITATIONS.
PORTER COUNTY											"PROPOSED ORDINANCE WHICH IS SIMILAR TO LAKE COUNTY"
ST. JOSEPH COUNTY										6.0	BUT NOT IN EXCESS OF $E_m=17.0Q_m^{-0.33}$ (Q_m IS TOTAL EQUIPMENT CAPACITY)
VIGO COUNTY											NOT TO CAUSE GROUND LEVEL CONCENTRATIONS TO EXCEED LIMITATIONS
ANDERSON											NO SO_2 REGULATIONS
EAST CHICAGO											SAME AS LAKE COUNTY
EVANSVILLE											NO SO2 REGULATIONS
GARY											SAME AS LAKE COUNTY

TABLE 61 (CONT'D.)

1975 REGULATIONS APPLICABLE TO FUEL BURNING SOURCES – ALLOWABLE EMISSIONS LBS $SO_2/10^6$ BTU

	FUEL LIMITATION % S (LBS S/10^6 BTU)		HEAT INPUT (MILLION BTU/HR)								REMARKS
	OIL	COAL	≤10	<50	100	<250	>250	1000	>2000	ALL	
HAMMOND	1.5	1.5									SAME AS LAKE COUNTY
INDIANAPOLIS											NO SO_2 REGULATIONS
MICHIGAN CITY											SAME AS LAKE COUNTY
WAYNE COUNTY											NO SO_2 REGULATIONS
IOWA										5.0 COAL 1.5 OIL	PROPOSED REGULATION – AFTER JANUARY 1, 1974; AFTER JANUARY 1, 1973: 6.0 LBS $SO_2/10^6$ BTU FOR COAL 2.0 LBS $SO_2/10^6$ BTU FOR OIL
KANSAS							3.0				
KENTUCKY											
PRIORITY I			4.0 COAL 2.5 OIL				1.2 COAL 0.8 OIL				2.0 COAL 1.5 OIL FOR 500 MILLION BTU/HR
PRIORITY II			4.0 COAL 2.5 OIL								
PRIORITY III			4.0 COAL 2.5 OIL					3.5 COAL 2.0 OIL			
LOUISIANA											2000 ppm
MAINE											
PORTLAND AQCR	1.5	1.5									
CENTRAL MAINE	2.5	2.5									
DOWNEAST	2.5	2.5									
AROOSTOOK CO.	2.5	2.5									
N.W. MAINE AQCR	2.5	2.5									
MARYLAND											
CUMBERLAND MD. AQCR	0.5 RESIDUAL 0.3 DISTILLATE	1.0									UNTIL JULY 1, 1975, 1% S WILL APPLY TO RESIDUAL OIL.
BALTIMORE AQCR	0.5 RESIDUAL 0.3 DISTILLATE	1.0									UNTIL JULY 1, 1975, 1% S WILL APPLY TO RESIDUAL OIL.
NATIONAL CAPITAL AQCR	0.5 RESIDUAL 0.3 DISTILLATE	1.0									SAME AS BALTIMORE
EASTERN SHORE AQCR	0.5 RESIDUAL 0.3 DISTILLATE	1.0									SAME AS BALTIMORE
SOUTHERN SHORE AQCR	0.5 RESIDUAL 0.3 DISTILLATE	1.0									SAME AS BALTIMORE
CENTRAL MD. AQCR	0.5 RESIDUAL 0.3 DISTILLATE	1.0									SAME AS BALTIMORE
MASSACHUSETTS											
CENTRAL MASS. AQCR	(0.17 NO. 2 OIL 0.55 OTHERS)	(0.55)									
MERRIMACK VALLEY AQCR	(0.17 NO. 2 OIL 0.55 OTHERS)	(0.55)									
BOSTON AQCR	(0.17 NO. 2 OIL 0.28 OTHERS)	(0.28)									FOR ARLINGTON, BELMONT, BOSTON, BROOKLINE, CAMBRIDGE, CHELSEA, EVERETT, MALDEN, MEDFORD, NEWTON, SOMMERVILLE, WALTHAM, WATERTOWN – FOR ALL OTHER TOWNS & CITIES IN THIS AQCR: FOR COAL & OIL 0.55 LBS S/10^6 BTU
PIONEER VALLEY AQCR	(0.17 NO. 2 OIL 0.55 OTHERS)	(0.55)									
S.E. MASS. AQCR	(0.17 NO. 2 OIL 0.55 OTHERS)	(0.55)									
BERKSHIRE	(0.17 NO. 2 OIL 0.55 OTHERS)	(0.55)									

TABLE 61 (CONT'D.)

1975 REGULATIONS APPLICABLE TO FUEL BURNING SOURCES – ALLOWABLE EMISSIONS LBS $SO_2/10^6$ BTU

	FUEL LIMITATION % S (LBS S/10^6 BTU)		HEAT INPUT (MILLION BTU/HR)								REMARKS
	OIL	COAL	≤10	<50	100	<250	>250	1000	>2000	ALL	
MICHIGAN	2.0 1.5	2.0 1.5								3.2 C 2.2 O 2.4 C 1.7 O	≤500,000 LBS STEAM PER HOUR BY JULY 1, 1975 FOR POWER PLANTS ONLY. >500,000 LBS STEAM PER HOUR BY JULY 1, 1975 FOR POWER PLANTS ONLY.
WAYNE COUNTY	0.3 DISTILLATE 0.7 HEAVY & CRUDE	0.5 PLANTS 0.3 RES.,COM.									AFTER AUGUST 1, 1975 - 1.25% S FOR PULVERIZED COAL FOR POWER PLANTS.
MINNESOTA	2.0	2.0									AFTER JUNE 1, 1974 - FOR FUEL BURNING SOURCES >250 MILLION BTU/HR & LOCATED OUTSIDE OF THE MINNEAPOLIS ST. PAUL AQCR.
MINNEAPOLIS - ST PAUL AQCR	2.0	2.0									AFTER JUNE 1, 1974 FOR ≤250 MILLION BTU/HR. ANY INSTALLATIONS >250 MILLION BTU/HR WILL HAVE THE FOLLOWING LIMITATIONS: AFTER JUNE 1, 1974 1.5% S FOR OIL AFTER JUNE 1, 1973 1.5% S FOR COAL AFTER JUNE 1, 1972 2.0% S FOR COAL
MISSISSIPPI										4.8	2.4 LBS $SO_2/10^6$ BTU FOR ANY MODIFIED FUEL BURNING UNIT (MODIFIED MEANS A PHYSICAL CHANGE IN AN AIR CONTAMINANT SOURCE WHICH INCREASES THE AMOUNT OF ANY AIR POLLUTANT EMITTED OR RESULTS IN THE EMISSION OF ANY AIR POLLUTANT NOT PREVIOUSLY EMITTED).
MISSOURI KANSAS CITY	2.0	2.0								2.3	STATE REGULATION INCLUDES ST. LOUIS METRO. AREA. SO_2 EMISSIONS SHALL NOT CAUSE AMBIENT AIR QUALITY LIMITATIONS TO BE EXCEEDED AT ANY OCCUPIED PLACE BEYOND THE PREMISES ON WHICH THE SOURCE IS LOCATED.
SPRINGFIELD-GREENE CO.										2.0	FOR EXISTING SOURCES; 0.5 LBS $SO_2/10^6$ BTU FOR NEW SOURCES. THIS REGULATION IS FOR SOURCES THAT BURN FUEL PRIMARILY TO PRODUCE HEAT AND WHERE THE SULFUR COMPOUND EMISSION IS DUE PRIMARILY TO THE SULFUR IN THE FUEL BURNED - FOR ALL OTHER SOURCES THE REGULATION SHALL BE NOT TO EXCEED AMBIENT AIR QUALITY LIMITATIONS.
MONTANA	(1.0)	(1.0)									
NEBRASKA											NOT IN EXCESS OF THE FOLLOWING: a) DURING ANY CONSECUTIVE 12 MONTH PERIOD, SULFUR OXIDES IN EXCESS OF THE AMOUNT EMITTED DURING 1971 CALENDAR YEAR b) DURING ANY 24 HR. PERIOD, SULFUR OXIDES EXCEEDING THE MAXIMUM AMOUNT EMITTED DURING ANY CONSECUTIVE 24 HR. PERIOD DURING 1971 CALENDAR YEAR.
NEVADA			1.4								0.105 X HEAT INPUT FOR ≥250 MILLION BTU/HR.
WASHOE CO. CLARK CO.	1.0 1.0										0.15x HEAT INPUT
NEW HAMPSHIRE	0.4 NO. 2 OIL 1.0 NO.'s 4, 5, & 6 OIL										AFTER OCTOBER 1, 1972

TABLE 61 (CONT'D.)

1975 REGULATIONS APPLICABLE TO FUEL BUSNING SOURCES — ALLOWABLE EMISSIONS LBS $SO_2/10^6$ BTU

	FUEL LIMITATION % S (LBS S/10^6 BTU)		HEAT INPUT (MILLION BTU/HR)								REMARKS
	OIL	COAL	≥10	<50	100	<250	>250	1000	>2000	ALL	
NEW JERSEY NJ-NY-CONN AND PHILADELPHIA AQCR'S NE PENN-UPPER DELAWARE AND NJ INTRASTATE AQCR	0.2 NO. 2 OIL 0.3 NO. 4 & HEAVIER OIL 0.3 NO. 2 OIL 0.7 NO 4 OIL 1.0 NO. 5 & HEAVIER	0.2 1.0 BITUMINOUS 0.7 ANTHRACITE									HIGHER % S COAL AND OIL CAN BE USED IF IT CAN BE DEMONSTRATED THAT THE SO_2 EMISSIONS CAN BE CONTROLLED SO AS NOT TO EXCEED 0.3 LBS $SO_2/10^6$ BTU.
NEW MEXICO ALBUQUERQUE-BERNALILLO CO.							0.34				NO SO_2 REGULATIONS
NEW YORK NJ-NY-CONN AQCR NIAGARA FRONTIER AQCR	(1.65) 0.3 RESIDUAL 0.2 DISTILLATE (0.6)	(2.00) 0.3 (1.4)									AFTER SEPT. 30, 1973; 0.1% S FOR DISTILLATE AFTER SEPT. 30, 1974; AFTER OCT. 1, 1971 FUEL CANNOT CONTAIN MORE THAN 0.2 LBS S/10^6 BTU GROSS HEATCONTENT AFTER OCT. 1, 1975 FOR OIL; AFTER OCT. 1, 1974 FOR COAL. EXCEPTIONS TO THE SULFUR LIMITATIONS ARE ALLOWED IF SULFUR EMISSIONS ARE NOT IN EXCESS OF THOSE PROVIDED BY THE RULE.
NORTH CAROLINA		1.0								1.6	FOR NEW INSTALLATIONS ONLY; 2.3 LBS $SO_2/10^6$ BTU FOR EXISTING INSTALLATIONS; BY 1980, 1.6 LBS $SO_2/10^6$ BTU FOR ALL INSTALLATIONS.
NORTH DAKOTA										3.0	
OHIO PRIORITY I REGIONS										1.0	REGIONS ARE: CINCINNATI, CLEVELAND, MARIETTA, N.W. OHIO, STEUBENVILLE, TOLEDO, YOUNGSTOWN, ZANESVILLE
PRIORITY II REGIONS										1.6	REGIONS ARE: DAYTON, MANSFIELD-MARION
PRIORITY III REGIONS										3.1	REGIONS ARE: COLUMBUS, PORTSMOUTH-IRONTON, SANDUSKY, WILMINGTON-CHILLICOTHE-LOGAN
OKLAHOMA										0.3 OIL 2.0 COAL	AFTER JULY 1, 1975, FOR NEW LIQUID BURNING EQUIPMENT. UNIIL THEN THE LIMITATION IS 0.8 LBS $SO_2/10^6$ BTU. THIS COAL LIMITATION IS FOR NEW EQUIPMENT ONLY; ONLY GROUND LEVEL CONCENTRATIONS ARE GIVEN FOR EXISTING FUEL BURNING EQUIPMENT.
OREGON	1.75 RESIDUAL 0.3 DISTILLATE	1.0				1.4 OIL 1.6 COAL	0.8 OIL 1.2 COAL				THE RESIDUAL OIL RESTRICTION APPLIES AFTER JULY 1, 1974. UNTIL THEN THE RESTRICTION IS 2.5% S EMISSION LIMITATIONS APPLY TO NEW SOURCES ONLY
COLUMBIA-WILLAMETTE MID WILLAMETTE LANE REGIONAL										1.0	1000 ppm 1000 ppm
PENNSYLVANIA PHILADELPHIA	0.2 NO. 2 & LIGHTER 0.3 NO. 4 & HEAVIER	0.3		3.0					1.8		$A=5.1E^{-0.14}$ lbs/10^6 BTU FOR $50 \leq$ HEAT INPUT ≤ 2000 OIL REGULATIONS APPLY AFTER OCTOBER 1, 1973; COAL REGULATIONS APPLY AFTER OCTOBER 1, 1972 - HIGHER % S FUELS CAN BE USED WHEN EQUIPMENT OR PROCESSES ARE USED TO REDUCE EMISSIONS.
ALLEGHENY CO. , BEAVER VALLEY, MONOGAHELA VALLEY, SE AIR BASIN				1.0					0.6		$A=1.7E^{-0.14}$ LBS/10^6 BTU FOR $50 \leq$ HEAT INPUT ≤ 2000
RHODE ISLAND	1.0	1.0									

TABLE 61 (CONT'D.)

1975 REGULATIONS APPLICABLE TO FUEL BURNING SOURCES – ALLOWABLE EMISSIONS LBS $SO_2/10^6$ BTU

	FUEL LIMITATION % S (LBS S/10^6 BTU)		HEAT INPUT (MILLION BTU/HR)								REMARKS
	OIL	COAL	≤ 10	< 50	100	< 250	>250	1000	>2000	ALL	
SOUTH CAROLINA										1.6 OIL 2.0 COAL	THESE REGULATIONS GO INTO EFFECT JULY 1, 1977; UNTIL THEN THE REGULATION FOR ALL FUELS IS 2.3 LBS $SO_2/10^6$ BTU – RESIDENCES OR DWELLINGS OF FOUR FAMILIES OR LESS ARE EXEMPT.
SOUTH DAKOTA										3.0	
TENNESSEE KNOX COUNTY CATTANOOGA-HAMILTON CO. DAVIDSON CO. MEMPHIS-SHELBY CO.	2.0	2.0									2000 ppm FOR EXISTING SOURCES BY AUG. 1, 1973 620 ppm FOR NEW SOURCES AND FOR ALL SOURCES BY JULY 1, 1975. REGULATIONS WILL BE UPDATED BY MARCH 30, 1972 TO CONFORM WITH THE STATE REGULATIONS. 2000 ppm AT 50% EXCESS AIR FOR EXISTING 620 ppm AT 15% EXCESS AIR FOR NEW SOURCE AND FOR ALL SOURCES AFTER JULY 1, 1975.
TEXAS GALVESTON & HARRIS CO.'S JEFFERSON & ORANGE CO.'S										3.0 C.	FOR STEAM GENERATORS. 400 ppm FOR OIL FOR STEAM GENERATORS. SO_2 EMISSIONS NOT TO CAUSE GROUND LEVEL CONCENTRATIONS EXCEEDING 0.28 PPM AVERAGED OVER A 30 MINUTE PERIOD SO_2 EMISSIONS NOT TO CAUSE GROUND LEVEL CONCENTRATIONS EXCEEDING 0.32 PPM AVERAGED OVER A 30 MINUTE PERIOD.
UTAH	1.5	1.0									
VERMONT	1.0	1.0									AFTER OCTOBER 1, 1974; BY OCTOBER 1, 1972 FUEL LIMITATION IS 1.5% S.
VIRGINIA											NOT IN EXCESS OF 2.64K=S WHERE K IS TOTAL CAPACITY RATING IN MILLION BTU/HR AND S IS ALLOWABLE EMISSIONS OF SULFUR OXIDES IN LBS/HR.WHERE ATTAINMENT OF AMBIENT AIR QUALITY STANDARDS IS REQUIRED, K CAN BE MULTIPLIED BY FACTORS 1.58 AND/OR 1.06.
WASHINGTON											1000 PPM FOR ALL SOURCES AFTER JULY 1, 1975 AND PRESENTLY FOR ALL NEW SOURCES; UNTIL THEN EXISTING SOURCES ARE RESTRICTED TO 2000 PPM.
PUGET SOUND	0.3 NO. 1 DISTILLATE										2000 ppm
SPOKANE CO.											NO SO_2 REGULATION
NORTHWEST	0.3 NO. 1 DISTILLATE									1.5	
SOUTHWEST											NO SO_2 REGULATIONS
OLYMPIC										1.5	
YAKIMA											NO SO_2 REGULATIONS
WEST VIRGINIA	1.5	2.0									EFFECTIVE 1975
PRIORITY I & II										2.7	EFFECTIVE JULY 1975 ONLY IF GENERATING STEAM FOR ELECTRIC POWER
PRIORITY III EXCEPT KANAWHA										3.2	EFFECTIVE JULY, 1975
KANAWHA VALLEY										1.6	EFFECTIVE JANUARY, 1973
WISCONSIN							0.8 O 1.2 C				FOR NEW SOURCES ONLY
WYOMING											NO SO_2 REGULATION GIVEN IN FINAL PLAN.
AMERICAN SAMOA	3.5	3.5								2.81	EFFECTIVE 1975; 1.94 LBS $SO_2/10^6$ BTU EFFECTIVE AS OF 1977.
GUAM										2.81	SAME AS FOR AMERICAN SAMOA.
PUERTO RICO	1.0	1.0									BY APRIL 1, 1975; 1.5% BY APRIL 1, 1974; 2.0% S BY OCTOBER 1, 1973; 0.5% BY APRIL 1, 1975 IN SAN JUAN, CATANO, GUAYNABO, & BAYAMON
VIRGIN ISLANDS	0.5										BY MARCH 1974; 1.0% BY MARCH 1973

SOURCE: Report of the Mitre Corporation for the Office of Air Programs, Environmental Protection Agency, *Analysis of Final State Implementation Plans—Rules and Regulations,* July 1972.

TABLE 62

PROCESS FOR DESULFURIZATION OF EFFLUENT GAS STREAMS

PROCESSES PRINCIPALLY IN THE GAS PHASE

No.	Process (Developer) (Reference)	Comments	Process Chemistry
YIELDING SULFURIC ACID OR SULFATE (S= +6)			
1	Dry limestone (TVA) (30)	Simultaneous reaction of SO_2 with lime and air oxidation of resulting sulfite to sulfate. End product slag requires suitable disposal. Swedish Bahco Process uses hydrated lime slurry (31). Lignite ash also used as absorber (Carl Still, W. Germany).	$CaCO_3 \longrightarrow CaO \xrightarrow{SO_2,\ SO_3,\ AIR} CaSO_4$ $+ CO_2$ (TO ATMOSPHERE)
2	Manganese dioxide (Mitsubishi) (25)	Initial concentration and oxidation of SO_2 to metal sulfate with air regeneration of MnO_2 oxygen carrier and ammonium sulfate (fertilizer) production.	$SO_2 \xrightarrow{MnO_2} MnSO_4 \xrightarrow[AIR]{NH_4OH} (NH_4)_2SO_4 + H_2O$ REGENERATION
3	Active magnesia (Showa Hatsuden) (Chemico) (32)	Essentially a concentration process using MgO as a "collector" followed by regeneration of concentrated SO_2 stream for sulfuric acid plant feed.	$SO_2 \xrightarrow[MgO]{200°-300°F.} MgSO_3 \xrightarrow{1400°F.} 15\%\ SO_2$ GAS REGENERATION CONTACT PROCESS H_2SO_4
4	Modified contact (Monsanto-Penelec) (Tokyo Tech.) (26)	Essential Contact Process yield acid (Monsanto) or ammonium sulfate (Tokyo) but accepts hot dilute SO_2 gas stream rather than high SO_2 acid plant feed. (see also Topsoe Process)	$AIR + SO_2 \xrightarrow[V_2O_5]{900°F.} SO_3 \xrightarrow{H_2O} H_2SO_4$ $SO_3 \xrightarrow{2NH_4OH} (NH_4)_2SO_4 + H_2O$
5	Modified chamber (Tyco Labs. Mass.) (24)	Updated version of Chamber Process for sulfuric acid, modified to accept dilute SO_2 stream. NO/NO_2 couple as oxygen carrier.	$SO_2 + H_2O + NO_2 \longrightarrow H_2SO_4 + NO$ $1/2\ O_2$
6	Activated carbon (Sulfacid-Lurgi) (Hitachi, Tokyo) (Reinluft, W. Germany) (Westvaco Corp. U.S.) (33, 34, 35, 36)	All method depend on absorptive powers of various forms active carbon to first concentrate and then catalyze oxidation SO_2 to SO_3 for acid or sulfate production. Fluidized, fixed and plugged flow beds variously employed.	$SO_2 \xrightarrow[ACTIVE\ CARBON]{AIR,\ H_2O} H_2SO_4$
YIELDING SULFUR (S=ZERO)			
7	Sulfreen (SNPA-Lurgi) (37)	Catalytic use of active carbon for high efficiency Claus redox reaction to yield sulfur rather than oxidation of SO_2 to $SO_4^{=}$. Requires both H_2S and SO_2 in stream.	$H_2S + SO_2 \xrightarrow{ACTIVE\ CARBON} H_2O + S$
8	Catalytic redox (Princeton Chem. Res.) (47, 48)	Essentially modified Claus redox with unspecified but claimed high efficiency catalyst. Where H_2S not present in feed can be generated from product S and natural gas.	$SO_2 + H_2S \xrightarrow[CATALYST]{250-350°F.} H_2O + S \longrightarrow$ $CO_2 \xleftarrow{CATALYST,\ HIGH\ TEMP.} CH_4$
9	CO/SO_2 redox (Chevron Research) (Univ. Mass. (29, 39)	Being examined with and without NO_x involved and at various temperatures; COS formation problem at lower temperatures.	$SO_2 + CO \longrightarrow 2CO_2 + S$ 1000°F, Cu ON Al_2O_3 NO PRESENT CONVERTED TO N_2
10	Alkalized alumina (U.S. Bur. Mines (discont.) (U.K. Cent. Elect. Board) (27)	Concentration of dilute SO_2 stream on alk/alumina and in situ catalytic reduction to H_2S using reformer H_2, H_2S then to Claus with regenerated SO_2.	$SO_2 \xrightarrow[56\%\quad 37\%]{Al_2O_3/Na_2O}$ ABSORBED $SO_2 \longleftarrow H_2 + CO$ REGENERATION REFORMER $S \xleftarrow[CLAUS]{SO_2} H_2S + CO_2$

TABLE 62 (CONT'D.)

PROCESS FOR DESULFURIZATION OF EFFLUENT GAS STREAMS

PROCESSES WITH AT LEAST ONE PRINCIPAL SOLUTION STAGE

No.	Process (Developer) (Reference)	Comments	Process Chemistry
YIELDING SULFATE (S=+6)			
11	Ammoniacal solution (Cominco) (Showa-Denko) (TVA) (Fulham Simon-Carves) (21, 22, 23)	Absorption and concentration of SO_2 and air in ammonia solution yields bisulfite and thiosulfate which subsequent undergo solution redox to yield (+6) and sulfur (zero). One of few solution processes yielding sulfate.	$SO_2 + NH_4OH \xrightarrow{AIR} 2NH_4HSO_3 + (NH_4)_2S_2O_3$; $\downarrow$ $(NH_4)_2SO_4 + H_2O + S$
YIELDING SULFUR (S=ZERO)			
12	Molten salt (Atomics Internatl.) (Garrett, Res. & Dev.) (28, 40)	Dilute SO_2 concentrated by absorption in molten salt as sulfite and reduced by H_2 (atomics) or coke roasting (garrett) to sulfide and hence H_2S. Both processes feed Claus.	$SO_2 + M_2CO_3(L) \xrightarrow{430°C} M_2SO_3 + CO_2$; $M_2SO_3 \xrightarrow{H_2 + CO}$ (NATURAL GAS REFORMATE OR COKE ROASTING) $M_2S + H_2O + CO_2$; $M_2S \xrightarrow{STEAM + CO_2} H_2S + M_2CO_3(L)$; $H_2S \rightarrow$ CLAUS $\rightarrow$ S, H_2O
13	Solution Claus IFP (Inst. Francais du Petrole) (9) see also Townsend (7) Shell (Deal) (8)	Essentially Claus redox in solution with or without added catalyst. High boiling solvents preferred to accept hot gases without extensive cooling.	$H_2S + SO_2 \xrightarrow[\text{POLYGLYCOL SOLVENT (M.W.} \sim 400)]{\text{METAL SALT CATALYST}} S + H_2O$
14	Bumines Citrate (U.S. Bureau of Mines) (43)	Claus solution redox here catalysed by forming intermediate citrate complex of SO_2 for reaction with H_2S. Catalytic H_2S formation from natural gas and sulfur if no H_2S in gas stream.	$SO_2 + H_2O \rightleftharpoons HSO_3^- + H^+$; $HSO_3^- + H_3Cit^- \rightleftharpoons (HSO_3 \cdot H_3Cit)^{-2}$ COMPLEX; COMPLEX $+ H_2S \rightarrow 3S + H_2O + H_3Cit$; $4S + CH_4 + 2H_2O \xrightarrow{Al_2O_3} H_2S$
15	Giammarco-Vetrocoke (same) (16, 17) see also Thylox (7)	Solution oxidation of H_2S absorbed as thioarsenite with arsenate/arsenite air regeneratable redox couple as oxygen carrier. Several similar systems involving inorganic redox couples (thylox, manchester, lacykeller (17, 18) exist.	$3H_2S + KH_2AsO_3 \rightarrow KH_2AsS_3 + 3H_2O$; $KH_2AsS_3 + 3KH_2AsO_4 \rightarrow 3KH_2AsO_3S + KH_2AsO_3$; $3KH_2AsO_3S \xrightarrow{1.5\ O_2\ (AIR)} 3KH_2AsO_4 + 3S$
16	Stretford (U.K. North W. Gas Board) (10, 12) see also Takahax (11)	Solution oxidation of H_2S absorbed as Bisulfide by two stage redox couple involving vanadate and anthraquinone disulfonic acid as oxygen carriers. Takahax uses napthaquinone.	$H_2S + Na_2CO_3 \rightarrow NaHS + NaHCO_3$; $NaHS + NaVO_3 \rightarrow S + Na_2V_2O_5 + Na_2CO_3 + H_2O$; REDOX: AQDSA$(O_2)$ / AQDSA; AIR O_2
17	Wellman-Lord (same) (44)	A solution method for concentrating dilute SO_2 stream to rich feed for Claus by bisulfite formation, crystallization and thermal regeneration. No reduction or oxidation in solution step.	$SO_2 + H_2O + M_2SO_3 \rightarrow 2MHSO_3$ (SOLN); $SO_2 + H_2O + M_2SO_3 \xleftarrow[\text{HEAT}]{\text{REDISSOLVE}} 2MHSO_3$ (XSTL); $H_2S \xrightarrow{\text{RICH FEED TO}}$ CLAUS $\rightarrow S$
18	Alkazid (Shell) (45)	Preliminary gas phase catalytic hydrogenation all sulfur compounds to H_2S followed by concentration in amino acid salt solution to yield rich Claus feed.	S + SULFUR COMPOUNDS $\xrightarrow{Co/Mo\ CAT}$ H_2S (REFORMER H_2/CO); $H_2S + RCH(NH_2)COONa \rightarrow (RCH(NH_3)^+COONa)_2S^=$ CONCENTRATE; $\xrightarrow{HEAT} H_2S \rightarrow$ CLAUS ($+SO_2$) $\rightarrow S$
19	Beavon (Parsons Co.) (12, 13)	Preliminary gas phase catalytic hydrogenation all sulfur compounds to H_2S for feed to Stretford. In particular COS and CS_2 reduced.	$(H_2), SO_2, COS, CS_2 \xrightarrow{Co/Mo\ CAT} H_2S$ (REFORMER H_2/CO); $H_2S \rightarrow$ STRETFORD $\rightarrow S$
20	Cleanair (Pritchard) (TGS) (14)	H_2S rich tail gas water cooled to continue Claus and hydrolyze. COS and CS_2; final H_2S to Stretford.	$H_2S(HIGH), SO_2, COS, CS_2 \xrightarrow[\text{COOLING}]{H_2O} H_2S + CO_2 + S$; FURTHER CLAUS; STRETFORD $\rightarrow S$

Source: Used by permission of the *Oil & Gas Journal*, August 28, 1972.

TABLE 63

SUMMARY OF DESULFURIZATION PROCESSES FOR FLUE GAS AND CLAUS UNIT TAIL GAS

Company	Process	Process Description	Status	Primary Application
Wellman-Power Gas	Aqueous Scrubbing Na_2SO_3	SO_2 is reacted with Na_2SO_3 in solution to form the bi-sulfite. When heated the pyrosulfite is formed, and is decomposed to produce SO_2 and solid Na_2SO_3 which is redissolved and recycled. $Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$ $2NaHSO_3 \rightarrow Na_2S_2O_5 + H_2O$ $Na_2S_2O_5 \rightarrow Na_2SO_3 + SO_2$	Several commercial units built	Flue gas, Claus plant and H_2SO_4 plant cleanup
Ralph M. Parsons - Union	Beavon Process (Reduction/ Stretford)	Sulfur in Claus Plant tail gas is reduced in fixed-bed catalytic reactor to H_2S. The H_2S is recovered by the Stretford Process (chemistry shown below) $H_2S + Na_2CO_3 \rightarrow NaHS + NaHCO_3$ $NaHS + 1/2O_2 \rightarrow NaOH + S$ (using anthraquinone and vanadate reagents as catalyst) $NaOH + NaHCO_3 \rightarrow Na_2CO_3 + H_2O$	Commercial unit under construction	Claus plant cleanup
Combustion Engineering	Wet Limestone Scrubbing	Limestone is injected into furnace to remove SO_3 and some SO_2. CaO in wet scrubber completes SO_2 removal. Furnace: $CaCO_3 \rightarrow CaO + CO_2$ $CaO + SO_2 \xrightarrow{O_2} CaSO_4$ Scrubber: $2Ca(OH)_2 + 2SO_2 \xrightarrow{O_2} CaSO_3 + CaSO_4 + 2H_2O$	Several commercial units built	Flue gas cleanup
USBM	Citrate Process	Flue gas is contacted with a sodium citrate solution, forming a citrate-bisulfite complex. In a separate section the complex is then reacted with H_2S to form sulfur and release the citrate for recycle. citr. + $SO_2 + H_2O \rightarrow$ (citr. HSO_3) (citr. HSO_3) + $H_2S \rightarrow S$ + citr. + H_2O	Piloted on smelter gas	Flue gas, smelter gas or Claus plant cleanup

TABLE 63 (CONT'D.)

SUMMARY OF DESULFURIZATION PROCESSES FOR FLUE GAS AND CLAUS UNIT TAIL GAS

Company	Process	Process Description	Status	Primary Application
Westvāco	Activated Carbon Adsorption	SO_2 is adsorbed on activated carbon and converted to H_2SO_4 in a fluidized bed. In another section the H_2SO_4 is converted to S with H_2S. Part of the S is used to generate the necessary H_2S. Other regeneration methods can be used. $SO_2 + 1/2O_2 + H_2O \longrightarrow H_2SO_4$ $H_2SO_4 + 3H_2S \longrightarrow 4S + 4H_2O$	Pilot Plant	Flue gas cleanup
Stone and Webster	Ionics	SO_2 is absorbed in NaOH, forming $NaHSO_3$ and Na_2SO_3. These are reacted with dil. H_2SO_4, forming SO_2 and Na_2SO_4. An electrolytic cell is used to convert the Na_2SO_4 to NaOH and H_2SO_4.	Pilot Plant	Flue gas or Claus plant cleanup
UOP	Sulfoxel	SO_2 is removed in an aqueous alkaline absorption system. The absorbent is then moved to a chemical section where the sulfite type material is catalytically converted to solid sulfur. Process is capable of removing sulfur to the level of a few ppm. The regenerated solvent is recycled to absorber.	Demonstration unit under construction	Flue gas cleanup
Foster-Wheeler	Bergbau-Forschung Activated Coal Coke Adsorption	A moving bed process where SO_2 in the presence of H_2O and and O_2 is converted to H_2SO_4 on the coke. Regeneration can produce H_2SO_4, SO_2 or throw-away product, depending on method used.	Unknown	Flue gas cleanup
J. F. Pritchard	CLEANAIR	A 3-stage process which consists of the following parts: Stage 1 - a catalytic process to convert COS and CS_2; Stage 2 - a proprietary process which removes about half the sulfur; Stage 3 - the Stretford process, which also removes about half the sulfur.	Several units contracted	Claus plant cleanup
MW Kellogg	KEL-S	Solid $CaCO_3$ in alkaline solution removes SO_2 in a modified venturi scrubber, forming $CaSO_4$, which is separated and can be discarded or regenerated as shown below: $CaSO_4$ + coke $\longrightarrow$ CaS (in rotary kiln) $CaS + H_2S \longrightarrow Ca\,(HS)_2$ $Ca\,(HS)_2$ + flue gas (CO_2) $\longrightarrow CaCO_3 + H_2S$	Unknown	Flue gas cleanup

TABLE 63 (CONT'D.)

SUMMARY OF DESULFURIZATION PROCESSES FOR FLUE GAS AND CLAUS UNIT TAIL GAS

Company	Process	Process Description	Status	Primary Application
Atomics Int'l. (North Amer. Rockwell Corp.)	Molten Carbonate	SO_2 reacts with molten carbonate to form sulfites and sulfates. Solution is reduced with H_2 and CO, then treated with CO_2 and H_2O to regenerate carbonate and produce H_2S.	Demonstration unit to be built	Flue gas cleanup
Chemical–Construction–Basic Chem. Company	Chemico-Basic MgO	SO_2 is reacted with magnesium oxide in a venturi scrubber to form magnesium sulfite. The sulfite is separated from solution and calcined to recover the SO_2 and regenerate magnesium oxide.	One commercial unit built	Flue gas cleanup
Monsanto	Cat-Ox	SO_2 is oxidized to SO_3 over a vanadium oxide catalyst. The SO_3 is absorbed in a circulating sulfuric acid stream to make 78% H_2SO_4 product.	Commercial unit under construction	Flue gas cleanup
Shell	Shell Flue Gas Desulfurization	SO_2 is reacted with CuO (on alumina) to form $CuSO_4$ in a fixed-bed cyclic process. Regeneration with a reducing gas produces a concentrated SO_2 stream and restores the copper.	Commercial unit under construction	Flue gas cleanup
Institut Francais du Petrole	IFP	The Claus reaction ($2H_2S + SO_2 \longrightarrow 3S + 2H_2O$) is carried out in an organic liquid. Process temperature is such that liquid sulfur is produced as a second phase.	One commercial unit built	Claus plant cleanup
Societe Nationale des Petroles	Sulfreen	The Claus reaction is carried out on activated charcoal to produce adsorbed liquid sulfur in a cyclic process. The sulfur is stripped with a hot inert gas.	Two commercial units built	Claus plant cleanup
Shell	SCOT (Reduction/Amine)	All sulfur compounds in the Claus tail gas (prior to incineration) are reduced to H_2S in a catalytic reactor. The tail gas is then treated in an amine adsorber for selective removal of H_2S for recycle to the Claus Plant. Treated tail gas is incinerated before discharge to the atmosphere. Final effluent concentrations of $<$500 ppm can be obtained.	Two commercial units built	Claus plant cleanup

SOURCE: American Petroleum Institute Division of Refining, "Summary of Desulfurization Processes for Flue Gas and Claus Unit Tail Gas," Paper presented at 37th Meeting of API, New York: May 9, 1972.

TABLE 64

AVERAGE VANADIUM IN
MAJOR PETROLEUMS,* PPM

°API gravity	Venezuela	Mid. East	California	U.S.†
10	1,000	–	–	–
15	320	–	160	–
20	205	–	88	59
25	160	–	55	(35)
30	100	56	(34)	(16)
35	42	(26)	(17)	(4)
40	(10)	(3.4)	(4.8)	

Note: Parenthesis indicates metals may not be troublesome.

*From Questions on Technology graph (OGJ, Mar. 14, 1966, p. 128).

†U.S., excluding California

Source: *Oil & Gas Journal.*

TABLE 65

PRODUCTION AND PROPERTIES OF
MIDDLE EAST CRUDES

	Crude		Reduced Crude		
Crude Source	Production 1,000 B/D	Gravity, °API	Gravity, °API	S, wt%	(Ni + V), ppm
Murban	564	39	24.9	1.5	2
Umm Shaif	93	37.4	–	–	–
Zakum	245	40	–	–	–
Khurais	22	33	14.6	3.3	31
Sassan	137	33	18.3	3.3	33
Kursaniyah	74	31	15.1	4.0	41
Arabian light	3,257	35-36	18.3	3.0	42
Zabair	83	35	18.1	3.3	43
Rumaila	480	35	–	–	–
Kuwait	2,951	30-32	16.7	3.9	60
Darius	100	34	12.8	4.7	61
Ahwaz	285	32.8	17	–	–
Kirkuk	1,097	36	15	–	80
Agha Jari	838	34	16.6	2.5	110
Marun	893	33.2	–	–	–
Paris	324	33.9	–	–	–
Ratawi	67	24	14.2	4.7	100
Safaniyah	791	27	12.7	4.26	102

Source: *Oil & Gas Journal.*

TABLE 66

PROCESSING SEQUENCES FOR PRODUCING LOW-SULFUR FUEL OIL MOST CHEAPLY

% sulfur in atmospheric residue	% sulfur in fuel oil product	Desulfurization of or by				
		Atmos go	Vac go	vb go	Residue, low metals	Coker go
Low sulf. (under 1.5)	1.0	A	—	—	—	—
Low sulf. (under 1.5)	0.5	G	G	—	—	—
Low sulf. (under 1.5)	0.3	V	V	V	—	—
Med. sulf. (1.5 - 3%)	1.5	G	G	—	—	—
Med. sulf. (1.5 - 3%)	1.0	V	V	V	—	—
Med. sulf. (1.5 - 3%)	0.5	R	R	—	R	—
Med. sulf. (high V)	0.5	C	C	—	—	C
Med. sulf. (high V)	0.3	C	C	—	—	C
High sulf. (over 3%)	2.0	G	G	—	—	—
High sulf. (over 3%)	1.5	V	V	V	—	—
High sulf. (over 3%)	1.0	R	R	—	R	—
High sulf. (high V)	1.0	C	C	—	—	C
High sulf. (high V)	0.5	R	V	—	R	—
High sulf. (high V)	0.3	C	C	—	—	C

Note:

A — Atmospheric distillation gas oil is desulfurized and mixed with the residue.

G — Vacuum flashing produces gas oils which are desulfurized and mixed with the residue.

V — The residue of vacuum flashing is viscosity broken and the atmospheric, vacuum and viscosity broken gas oils are desulfurized.

R — Vacuum flash bottoms are directly desulfurized as well as atmospheric and vacuum gas oil.

C — The vacuum flash bottoms are coked and three gas oils (atmospheric and coke) which constitute the fuel oil are desulfurized.

Source: *Oil & Gas Journal.*

TABLE 67

COMMERCIAL DESULFURIZATION PROCESSES FOR FUEL OILS*

Process	Developed By	Type Charge	Commercial Capacity On-Stream or Planned
VGO Isomax	Chevron Research Co.	Vacuum Gas Oil	300,000 B/SD On-stream
RDS, VRDS Isomax	Chevron Research Co.	Reduced Crudes	None Reported
H-Oil	Cities Service Research and Hydrocarbon Res., Inc.	Atmospheric or Vacuum Residuum	52,500 B/SD On-stream (3 Units)
Go-fining	Esso Research and Engineering Co.	Virgin and Cracked Gas Oils	390,000 B/SD On-stream 580,000 B/SD Planned
Residfining and Flexicoking	Esso Research and Engineering Co.	Reduced Crudes	None Reported
Gulf HDS, Types I, II and III	Gulf Research and Development Co.	Atmospheric Residuum	80,000 B/SD On-stream (2 Units) 45,000 B/SD Planned (1 Unit)
Heavy Gas Oil Gulfining	Gulf Research and Development Co.	Virgin and/or Cracked Heavy Gas Oils	70,000 B/SD On-stream (6 Units)
IFP Resid. and Vac. Gas Oil Hydrodesulf.	Institute Francais de Petrole	Reduced Crudes	Two Units On-stream Capacity Not Reported
Resid. Ultrafining	Standard Oil Co. (Ind.)	Reduced Crudes	None Reported
Vac. Gas Oil Ultrafining	Standard Oil Co. (Ind.)	Vacuum Gas Oil	None Reported
RCD Isomax	Univ. Oil Products Co.	Not Reported	75,000 B/SD On-stream (2 Units)
RCD Isomax	Univ. Oil Products Co.	Atmospheric Residuum	45,000 B/SD On-stream (1 Unit)

* "A Special Report—Hydrodesulfurization Technology Takes on the Sulfur Challenge," by Leo Aalund, Refining Editor, *The Oil and Gas Journal,* September 11, 1972.

APPENDIX G

Comparisons of Tax Structures of Several Countries

TABLE 68

COMPARATIVE CORPORATE TAX RATES
FRENCH CARIBBEAN—GUADELOUPE

Corporate Income Tax	50%	(On two-thirds of earned profits or 33-1/3% effective rate)
Excess Profits Tax	None*	
Dividend Tax (foreign shareholder)	5% - 25%	(5% - 10% for a U.S. shareholder)
Typical Manufacturer's Tax Load†	36-2/3%	(Assumes all earning paid as dividend)
Tax on Branch Profits	40%	(33-1/3% company tax plus 6-2/3% for dividends to a U.S. holder)
Tax on Royalties	0 - 5%, 24%‡	
Tax on Interest ‖	25%	(10% for interest paid from France to the U.S.)
Normal Depreciation Allowances	Straight line or accelerated	(Carry-forward's subject to negotiation)
Loss Carry-forward	5 years*	
Annual Tax on Capital		(Registration tax of 0.25%, Real property transfer [17%], Business tax)
General Sales or Turnover Tax§	Value added tax	(Export sales from a refinery exempt)
Major Tax Incentives		(It may be possible to obtain a "custom-free zone" for unrestricted entry and exit of certain items. "Privileged tax treatment status may allow: tax exemption on reinvested profits, corporate tax exemption in certain activities, job creation exemptions of taxes." Further tax incentives may be given to companies qualifying as "long-term tax regimes.")

* In France

† Aggregate burden of taxes on corporate income, excess profits, dividends and capital, for a wholly foreign-owned subsidiary not benefiting from incentives. Computation assumes that company has capital base (as defined by taxing country) of $1 million, earns pre-tax net income of $200,000 and declares gross dividend of $100,000.

‡ France: Tax is generally withheld on royalties paid to non-residents at the rate of 24% on 70-80% of the royalties. The treaty with the United States provides that no tax is withheld on royalties on artistic, literary, or scientific copyrights and that royalties or other payments for the use of patents, trademarks and similar property and for know-how are subject to withholding tax at the rate of 5%.

‖ Tax on payments to foreign non-bank lender.

§ Certain products may bear higher rates or be exempt.

TABLE 69

COMPARATIVE CORPORATE TAX RATES
U.S. CARIBBEAN—PUERTO RICO

Corporate Income Tax	22% plus 9 - 18% surtax	
Excess Profits Tax	None	
Dividend Tax (foreign shareholder)	15% or 29%	(29% rate applies to profits derived from activities other than manufacturing, shipping, or hotels)
Typical Manufacturer's Tax Load*	42%	
Tax on Branch Profits	22% plus 9 - 18% surtax	(On local source income only. Dividends distributed by parent company pay 15% or 29% [see dividend tax] if 20% or more of parent's gross income is derived from Puerto Rico)
Tax on Royalties	15% or 29%	(29% rate applies to profits derived from activities other than manufacturing, shipping, or hotels)
Tax on Interest†	15% or 29%	(29% rate applies to profits derived from activities other than manufacturing, shipping, or hotels)
Normal Depreciation Allowances	2.25 - 3% on buildings, 5 - 10% on heavy machinery	(Flexible system may be used for hotel manufacturing, or construction)
Loss Carry-forward	5 years	
Annual Tax on Capital	3% property tax	(Lower rates outside San Juan)
General Sales or Turnover Tax‡	Excise taxes of 5 - 20% on "taxable price" of certain articles	(There is also a small, municipally levied license [patente] tax based on annual gross sales)
Major Tax Incentives	Qualifying firms are entitled to tax exemptions of 10 - 20 years, depending on location, including 100% exemption from income tax, property tax, patent and other municipal taxes, and excise taxes (Sun Oil's refinery received a 17 year exemption). The law also provides a choice of percentage tax deductions with a corresponding extension of the exemption (i.e., 50% for twice the time). Dividends paid by tax exempt corporations are exempt from withholding tax if paid to bonafide residents or to foreign shareholders who are not taxed on such dividends in their country of domicile. In all other cases they are subject to the reduced 15% withholding tax. Capital gains from sales of stock in an exempted business are tax exempt during the exempt period. In addition, tax-exempt corporations may obtain a 10-year tax exemption on their export income to destinations other than the U.S. Cash grants are available in less developed areas, based on employment. Other operational and licensing aids are provided.	

* Aggregate burden of taxes on corporate income, excess profits, dividends and capital, for a wholly foreign-owned subsidiary not benefiting from incentives. Computation assumes that company has capital base (as defined by taxing country) of $1 million, earns pre-tax net income of $200,000 and declares gross dividend of $100,000.

† Tax on payments to foreign non-bank lender.

‡ Certain products may bear higher rates or be exempt.

TABLE 70

COMPARATIVE CORPORATE TAX RATES
BRITISH CARIBBEAN–JAMAICA

Corporate Income Tax	35%, plus 37.5% "additional" company profit	(Wholly-owned foreign subsidiaries deduct the regular 35% company tax and 26% of their taxable income before calculating the 37.5% "additional" company profits tax)
Excess Profits Tax	None	
Dividend Tax (foreign shareholder)	12.5% on first $850 (Jamaican), 37.5% on rest	(37.5% income tax is paid by company on behalf of shareholders, and credited against the 37.5% "additional" company profits tax)
Typical Manufacturer's Tax Load*	39%	
Tax on Branch Profits	45%	
Tax on Royalties	12.5%	
Tax on Interest†	12.5%	
Normal Depreciation Allowances	2.5 - 5% on buildings, 7.5 - 10% on machinery, 20% on vehicles	(Also 20% initial allowance in year of investment)
Loss Carry-forward	6 years	
Annual Tax on Capital	None	
General Sales or Turnover Tax‡	Excise taxes on certain products	
Major Tax Incentives	Full or 50% exemption for 10 - 15 years, depending on location	

* Aggregate burden of taxes on corporate income, excess profits, dividends and capital, for a wholly foreign-owned subsidiary not benefiting from incentives. Computation assumes that company has capital base (as defined by taxing country) of $1 million, earns pre-tax net income of $200,000 and declares gross dividend of $100,000.

† Tax on payments to foreign non-bank lender.

‡ Certain products may bear higher rates or be exempt.

TABLE 71

COMPARATIVE CORPORATE TAX RATES
CANADA (EAST)—NEW BRUNSWICK, NEWFOUNDLAND

Corporate Income Tax	50%	(To be reduced to 46% at 1% per year. Half of capital gains are included in taxable income. A 7% rebate of corp. tax is allowed in 1972). Plus 13% Newfoundland; 10% New Brunswick (may be credit against federal rate up to 10% in some cases)
Excess Profits Tax	None	
Dividend Tax (foreign shareholder)	10 - 15%	(To be increased to 25% in 1976 unless exempted by treaty. The 10% rate applies to resident Canadian companies meeting certain standards)
Typical Manufacturer's Tax Load*	53 - 56%	
Tax on Branch Profits	50% - 15%	(Differs from "normally" corporate income tax in that the equivalent dividend tax is charged immediately on income in excess of prescribed allowance respecting increased investment in property in Canada)
Tax on Royalties	15%	
Tax on Interest†	15%	
Normal Depreciation Allowances	Straight line and accelerated 20% machinery 30% vehicles 10% wooden buildings 5% other buildings	
Loss Carry-forward	5 years	
Annual Tax on Capital	None	
General Sales or Turnover Tax‡	Federal sales tax 12%. Excise tax on luxury items. Provincial sales tax: 8% New Brunswick; 7% Newfoundland. (Sales and excise taxes are rebated on exports but generally added to imports)	
Major Tax Incentives	Just about all provinces will supply capital funds for worthwhile undertakings. Terms and conditions vary. The best results come from personal contact with provincial authorities. Newfoundland makes loan guarantees and offers lower power rates (2.5 mills) for large users. New Brunswick makes loans for machinery and equipment and builds plants of leaseback basis. The Federal Government grants 99% drawbacks of duty on materials and components that are imported for subsequent exports in finished goods. Also available depreciation deferral or acceleration, tariff concessions, cash grants (oil refining not eligible) R & D incentives.	

* Aggregate burden of taxes on corporate income, excess profits, dividends and capital, for a wholly foreign-owned subsidiary not benefiting from incentives. Computation assumes that company has capital base (as defined by taxing country) of $1 million, earns pre-tax net income of $200,000 and declares gross dividend of $100,000.

† Tax on payments to foreign non-bank lender.

‡ Certain products may bear higher rates or be exempt.

TABLE 72

COMPARATIVE CORPORATE TAX RATES
BAHAMAS

Corporate Income Tax	None
Excess Profits Tax	None
Dividend Tax (foreign shareholder)	None
Typical Manufacturer's Tax Load*	None
Tax on Branch Profits	None
Tax on Royalties	None
Tax on Interest	None
Normal Depreciation Allowances	Does not apply
Loss Carry-forward	Does not apply
Annual Tax on Capital	A nominal real property tax, based on 12-1/2% of the assessed rental value on property in New Providence. Annual $250 fee.
General Sales or Turnover Tax	A 2¢ sales tax on gasoline only. Import duties are high on non-essential items. The normal ad valorum rate is 20%. An additional emergency rate of 7-1/2% is also applied. Many items of machinery, tools, equipment and necessary raw materials are exempt. Approved manufacturers are exempt. Stamp taxes are imposed on various documents.
Major Tax Incentives	Note: There is *no* tax treaty with the United States avoiding double taxation. Bahamas and the United States do *not* have a bilateral agreement providing an investment guarantee covering war, expropriation or inconvertibility of currency. As a member of the British Commonwealth, the Bahamas gives preference tariff rates to imports from Britain and other Commonwealth countries. Attractive long term leases. Capital gains exemptions. Excise tax, custom duty and stamp tax exemptions.

* Based on $200,000 income and $100,000 dividend.

TABLE 73

COMPARATIVE CORPORATE TAX RATES
TRINIDAD AND TOBAGO

Corporate Income Tax	45%
Excess Profits Tax	None
Dividend Tax (foreign shareholder)	10 - 30%. There is a 30% tax withheld on distributed profits to non-residents. If a Trinidad company makes a distribution to a non-resident parent company, the rate is reduced to 15% (10% in the United States).
Typical Manufacturer's Tax Load*	50%
Tax on Branch Profits	30% withholding tax is charged on non-resident company's branch profits whether remitted or not.
Tax on Royalties	15%
Tax on Interest	15%
Normal Depreciation Allowances	2-1/2% - 5% industrial buildings. 10 - 20% machinery and equipment. 25% vehicle.
Loss Carry-forward	Trading losses may be carried forward indefinitely and setoff against subsequent profits. However, the amount of the setoff in any one year is limited to one-half of the taxable profits.
Annual Tax on Capital	Nominal registration tax.
General Sales or Turnover Tax	No sales tax. Purchase tax 3 - 45%. Excise taxes are applied on domestically produced gasoline and kerosine. 2% real estate conveyance tax. Import duties. 5% unemployment tax.
Major Tax Incentives	Note: There is a tax treaty with the United States avoiding double taxation. Trinidad and Tobago have a bilateral agreement with the United States providing an investment guarantee covering war, expropriation and inconvertibility of currency. There is a 5-year tax exemption from the date of initial production for new industries in the majority of cases. The exemption may be extended 5 more years by special legislation. Commencing January 1, 1969, the tax holiday for new "Pioneer Industries" in normal cases was reduced from 5 to 3 years and a system of graduated corporate tax rates became effective upon expiration of the tax holiday. Under revised guidelines some areas were exempted from 100% foreign participation. Some foreign operations were forced to give Trinidadians the opportunity to get equity positions and learn all aspects of the business operations. An export allowance is given on increased exports.

* Based on $200,000 income and $100,000 dividends.

TABLE 74

COMPARATIVE CORPORATE TAX RATES
VIRGIN ISLANDS

Corporate Income Tax	Taxes are based basically on U.S. code.
Excess Profits Tax	Taxes are based basically on U.S. code.
Dividend Tax (foreign shareholder)	Taxes are based basically on U.S. code.
Typical Manufacturer's Tax Load*	Taxes are based basically on U.S. code.
Tax on Branch Profits	Taxes are based basically on U.S. code.
Tax on Royalties	Taxes are based basically on U.S. code.
Tax on Interest	Taxes are based basically on U.S. code.
Normal Depreciation Allowances	Taxes are based basically on U.S. code.
Loss Carry-forward	Taxes are based basically on U.S. code.
Annual Tax on Capital	Property tax 1-¼% rate on 60% market value.
General Sales or Turnover Tax	6% import tax (90% rebates possible). Excise tax 2 - 10% (100% exemption allowed). Gross receipts tax 2%. Stamp tax 0.1% - 1%. Gasoline 6¢/gal. Import 3 - 10% including LNG, fuel oil.
Major Tax Incentives	No industrial Incentive Act is in force today, the previous act expired December 1970. Expected reinstatement in 1972 may include: (1) 90% subsidy based on import duties levied on goods necessary for producing or creating an article; (2) non-taxable subsidy equal to 75% of the income tax liability; (3) non-taxable subsidy equal to 75% of the income tax liability on dividends for stockholders of exempt corporations, providing the stockholder is a bonafide resident of the Virgin Islands; (4) real property tax exemption; (5) exemption of excise (local) taxes on materials used in construction and operation of exempt business; (6) exemption of all annual or specific licenses. Business must be created in Virgin Islands.

* Based on $200,000 income and $100,000 dividends.

TABLE 75

COMPARATIVE CORPORATE TAX RATES
NETHERLANDS ANTILLES (ARUBA AND CURACAO)

Corporate Income Tax	27 - 34% + 15% surtax (graduated tax rate) imposed in Aruba and Curacao.
Excess Profits Tax	Petroleum refining companies established in the Netherlands Antilles pay a profits tax on their Antilles operation equal to 61¢ per 1,000 kilograms of products shipped.
Dividend Tax (foreign shareholder)	0 - 5%
Typical Manufacturer's Tax Load*	31 - 39%
Tax on Branch Profits	?
Tax on Royalties	None?
Tax on Interest	None?
Normal Depreciation Allowances	10% on machinery and equipment.
Loss Carry-forward	5 years (a loss sustained in the first 6 years of operation can be carried forward indefinitely.)
Annual Tax on Capital	Minor registration fee.
General Sales or Turnover Tax	No sales tax. Minor stamp tax. Various real estate use, transfer and rental taxes. Free zones exist for entry and exit of goods.
Major Tax Incentives	Note: There is a treaty with the United States avoiding double taxation as a result of the extension of the treaty with the Netherlands ratified in 1948. Netherlands Antilles and the United States have a bilateral agreement providing an investment guarantee covering expropriation and inconvertibility of currency under an arrangement with the Netherlands to include her territorial dependencies. The absolute rate of profit tax charged investment, rental and holding companies during their first year of operation cannot be raised during the 10 years immediately following. Profits of enterprises operating in the Curacao free zone until January 1, 1981, only pay 1/3 of the normal tax as long as the products do not physically pass through the free zone or the Netherlands Antilles or 13.03% if the profits have not been derived from domestic sales.

* Based on $200,000 income and $100,000 dividend.

APPENDIX H
A Case Study of Environmental Drain on Capital

A CASE STUDY OF ENVIRONMENTAL DRAIN ON CAPITAL

The requirement for capital to be invested in nonincome producing facilities due to regulations or standards inposed upon the refining industry is one of the reasons for the shortage of refining capacity. To demonstrate the magnitude of this drain on available capital, a specific situation has been examined.

This mid-continent refinery has a nominal crude capacity of 85 MB/CD charging a mixture of crudes brought in by pipeline from west Texas, Oklahoma, Kansas, Montana and Wyoming. Refinery process equipment consists of crude desalting, crude distillation, a vacuum unit charging atmospheric topped crude, a fluid catalytic cracker, a catalytic reformer, an alkylation unit, a straight-run distillate hydrodesulfurization unit, light ends recovery and separation units, various gas and liquid treaters, a sulfur plant, gasoline and distillate blenders, steam boilers and tankage. The plant fuel supply consists of heavy fuel oil, purchased natural gas and plant residue gas. The product slate produced includes LPG, gasoline, jet fuels, diesel fuel, distillate fuel oils, heavy residual fuel oil, asphalt and road oils and sulfur.

In order to meet proposed EPA requirements for 1975 gasolines, along with 1975 air and water quality standards, additions to or revisions of process equipment will be necessary. The necessary changes, listed below along with estimated capital requirements (1970 dollars), are summarized in Table 76.

CHANGES REQUIRED TO MEET 1975 EPA REQUIREMENTS

Produce Lead-Free Motor Fuel--92.3 RON Clear Pool

• Replace bauxite desulfurization unit on catalytic reformer charge with a hydrodesulfurization unit	\$3,400,000
• Revise catalytic reformer to produce 97 RON clear reformate at the maximum charge rate by adding a fourth reactor and a new heater. Unit limited to about 90 RON clear or less	\$1,470,000
• Revise alkylation unit to improve alkylate RON	\$3,800,000
• Install C_5-C_6 isomerization unit to convert all NC_5 to IC_5 and isomerize C_6's once through	\$7,200,000
• Total Investment	\$15,870,000

TABLE 76

EXAMPLE REFINERY INVESTMENT REQUIRED TO MEET
1975 ENVIRONMENTAL STANDARDS

	Period 1968 - 1975			
	Base Crude Slate		International Crude	
	Investment ($M)	Incremental Mfg. Exp. ($/Bbl Crude)	Investment ($M)	Incremental Mfg. Exp. ($/Bbl Crude)
Lead Free Motor Fuel	15,870	0.148	15,870	0.148
Air and Water Quality	6,792	0.016	7,390	0.017
Low-Sulfur Distillate	2,210	0.006	2,600	0.008
Low-Sulfur Heavy Fuel Oil	8,800	0.046	—	—
Heavy Oil FCC	—	—	17,000	0.062
Total	33,672*	0.216	42,860	0.235
Capital Charge Rate, DCF	15%	10%	15%	10%
Incremental Manufacturing Expense ($/Bbl Crude)	0.216	0.216	0.235	0.235
Capital Charges ($/Bbl Crude)	0.364	0.260	0.463	0.332
Additional Cost of Crude Transportation	—	—	0.270	0.270
Increased Revenue Required ($/Bbl Crude)	0.530	0.476	0.968	0.837

* Assuming new refinery capacity costs $2,200 per daily barrel, $33,672,000 would buy 15.3 MB/CD of refinery capacity.

Meet 1975 Ambient Air Quality

The 1968 refinery configuration was as follows: smokeless flares, a CO boiler on the fluid catalytic cracker, an acid gas amine scrubber on the refinery residue gas, a sulfur plant and a molecular seal on the crude unit flare stack.

The following items will be required to meet 1975 air quality standards:

- Improve operation of electrical precipitator on catalytic cracker $ 70,000
- Install catalyst fines disposal system on catalytic cracker $ 60,000
- Install soot blowers on CO boiler $ 50,000
- Modernize steam boiler control system $ 24,000
- Improve disposal facilities for sour water stripper overhead gas $ 50,000

- Hydrocarbon controls--cover API separator, loading rack vapor recovery system, inner floating roofs for certain tanks — $ 500,000
- Odor control as needed — $ 50,000
- Control sulfur emissions at cat cracker (an amount shown even though the process is not commercially proven in this application) — $3,500,000
- Total Investment — $4,304,000

New units to be added will have any necessary air pollution control equipment included as a part of the capital requirement.

Meet 1975 Water Effluent Quality

The 1968 refinery configuration was as follows: pollution control facilities for waste water which included air flotation, centrifuges and a sour water stripper. Additional items required to meet 1975 water quality standards are as follows:

- Improve sewers in certain areas — $ 38,000
- Install biological treatment for waste water — $1,500,000
- Segregation and handling of storm water — $ 350,000
- Segregate sanitary sewage and pump to treatment system — $ 150,000
- Reduce fluorides in waste water — $ 150,000
- Incinerator for heavy oils and sludges — $ 300,000
- Total Investment — $2,488,000
- Total Investment for Air and Water — $6,792,000

Produce Low-Sulfur Distillate

This will require the installation of a light cycle oil hydrodesulfurization unit since the FCC light cycle oil is the only distillate stream not hydrodesulfurized. This will require a 10 MB/CD unit.

$2,210,000

Produce Low-Sulfur Fuel Oil--0.5 Percent

Production of low-sulfur oil will require the installation of residuum hydrodesulfurization facilities. This would require a unit capable of charging about 7 MB/CD of residual fuel with the base crude slates. Also, a 4 million standard cubic feet per day (MMSCF/D) hydrogen plant (steam naphtha), amine scrubber to recover H_2S and a 17 long tons per day (LT/D) sulfur plant with tail gas scrubbing will be required.

• Residuum hydrodesulfurization	$6,350,000
• H_2 plant	$ 900,000
• Amine scrubber and sulfur plant	$1,300,000
• Tail gas scrubbing for sulfur unit	$ 250,000
• Total Investment	$8,800,000

A hydrogen plant will be necessary since the other three hydrodesulfurization units--naphtha, straight-run distillate and light cycle oil--will consume most of the reformer hydrogen.

PROCESS INTERNATIONAL CRUDE SUCH AS ARABIAN LIGHT

Since it appears that the supply of domestic crude will decline, it was assumed that eventually an international crude, such as Arabian Light, will be available to replace domestic crude. This will require some additional heavy ends processing equipment since the Arabian Light crude has more 1,050°F+ material and more sulfur than the base crude slate.

One possibility would be to make asphalt and road oils out of all the residuum produced. This would require an increase in vacuum unit capacity and additional storage and blending facilities. This would produce about 13.2 MB/CD (195 MM gallons per year) of asphalt and road oils. This is 2½ times the base case operation, so probably is not a feasible processing procedure.

Another possibility would be to install a residuum hydrodesulfurization unit charging 11.9 MB/CD of residuum and producing a low-sulfur (0.5 percent) heavy fuel oil. Besides the residuum hydrodesulfurization unit, an 8 MMSCF/D hydrogen plant (steam naphtha), an amine scrubber for H_2S recovery, and a 65 LT/D sulfur plant with a sulfur plant tail gas clean-up unit would be required.

• Residuum hydrodesulfurization (uncertain technology)	$ 8,700,000
• Amine scrubber and sulfur plant	$ 2,750,000
• Tail gas scrubber for sulfur unit	$ 500,000
• H_2 plant	$ 1,300,000
• Total Investment	$13,250,000

This much fuel oil, as with the asphalt processing, far exceeds base case operation. It would require shipping the heavy fuel oil great distances out of the area, which makes this processing scheme uneconomical.

A third possibility would be to install a heavy oil fluid cat cracking (FCC) unit charge 15 MB/CD of residuum and topped crude. This is a fluid cat cracking unit designed to convert topped crude into light ends, gasoline, distillate and coke with the liquid products having a lower sulfur content than the raw charge. This unit would require some kind of SO_2 recovery equipment on the regenerator flue gas stream.

• Heavy oil FCC unit	$12,000,000
• Control sulfur emissions	$ 5,000,000
• Total Investment (an amount shown even through the process is not commercially proven for this application).	$17,000,000

Glossary

GLOSSARY

additives--any materials incorporated in finished petroleum products for the purpose of improving their performance in existing applications or for broadening the areas of their utility.

alkylate--a synthetic gasoline of high octane number used in aviation and motor gasoline produced from an olefin and isoparaffin.

alkylation--a refinery process for chemically combining isoparaffin with olefin hydrocarbons. The product, alkylate, has high octane value and is blended with motor and aviation gasoline to improve the antiknock value of the fuel.

alumina--a naturally occurring type of clay containing a high percent of hydrated aluminum oxide commonly referred to as bauxite. Also a synthetically produced hydrated aluminum oxide of high purity. Used in refining processes as a drying agent and as a support for certain catalysts.

ambient--a term usually referring to surrounding conditions.

amine--a class of organic compounds of nitrogen that may be considered as derived from ammonia (NH_3).

analog computer--computer that operates with numbers represented by directly measured quantities.

antiknock--a quality to reduce autoignition knock in gasoline engines.

°API gravity--American Petroleum Institute gravity is an expression of the density or the weight of a unit volume of material when measured at a temperature of 60°F.

aromatic hydrocarbons--hydrocarbons characterized by the presence of a six-membered, unsaturated ring structure of carbon atoms. Examples include benzene, toluene and xylenes.

ash--the amount of nonvolatile material left after complete burning of the oil.

asphalt cement--a refined asphalt, or combination of refined asphalt and flux, of suitable consistency for paving purposes.

base oil--a refined or untreated oil used in combination with other oils and additives to produce lubricants.

benzene--clear, colorless, extremely flammable liquid of molecular weight 78.11 found as a high octane component of catalytic reformate. Used in organic synthesis and as a solvent.

biodegradable detergents--detergents susceptible to destruction by bacteria especially in sewage treatment plants.

blending--the process of mixing two or more oils having different properties to obtain a final blend having the desired characteristics. This can be accomplished "off-line" as a batch process or automated "in-line" as part of the continuous flow of a refinery.

bright stocks--high viscosity, fully refined and dewaxed lubricating oils produced by the treatment of residual stocks and used to compound motor oils.

butane--a hydrocarbon of the paraffin series, consists of 4 carbon atoms and 10 hydrogen atoms. A naturally occurring component of crude oil and natural gas as produced at the well. A gas at room temperature and atmospheric pressure. Used in motor fuel, as petrochemical feedstocks, and as LPG (bottle gas).

butylene--a hydrocarbon of the olefin series, consists of 4 carbon atoms and 8 hydrogen atoms. A product of a cracking operation and a gas at ambient temperature and atmospheric pressure. May be used as a component of motor fuel, feed to an alkylation unit, or in petrochemical operations.

carbon monoxide--colorless, odorless, very toxic gas formed as a product of incomplete combustion of carbon (as in water gas and producer gas, exhaust gases from internal combustion engines).

carbon residue--the amount of carbonaceous material left after evaporation and pryolysis of an oil.

catalyst--a substance capable of changing the rate of reaction without itself undergoing any net change.

catalytic cracking--a refinery process that converts a high boiling range fraction of petroleum (gas oil) to gasoline, olefin feed for alkylation, distillate, fuel oil and fuel gas by use of a catalyst and high temperature.

catalytic cracking unit--a refinery process unit that converts a high boiling range fraction of petroleum (gas oil) to gasoline, olefin feed for alkylation, distillate, fuel oil and fuel gas by use of a catalyst and high temperature.

catalytic hydrorefining--a refining process that replaces sulfur and nitrogen in high boiling point range fraction of petroleum (such as residual fuels, heavy gas oils and catalytic cracking and recycle feedstocks) with hydrogen by use of a catalyst, high temperature and a high ratio of hydrogen to feed.

catalytic hydrotreating--a refining process that replaces sulfur and nitrogen and saturates intermediate range boiling point fractions of petroleum (such as catalytic reformer feedstocks, naphtha and straight-run distillates) with hydrogen by use of catalyst, high temperature and a high ratio of hydrogen to feed.

catalytic reforming--a catalytic process used to improve the anti-knock quality of low octane gasoline by conversion of naphthenes (such as cyclohexane) and paraffins into higher octane aromatics such as benzene, toluene and xylenes.

cetane index or cetane number--a term indicating quality of diesel fuel as octane number indicates a quality of gasoline.

chelating agents--a metal deactivating additive that chemically combines with a metal to make it inactive. Especially useful where metals may be present in extremely small quantities.

clear octane--the octane number of a gasoline before the addition of antiknock additives such as TEL or TML.

cloud point--the temperature at which paraffin wax or other solid substances begins to crystallize out or separate from solution when an oil is chilled under specified conditions.

cobalt--a tough, lustrous, silver-white metal related to iron and nickel. In refinery use, cobalt oxide is combined with molybdenum oxide to make a catalyst used in hydrodesulfurization units.

coke--the solid residue remaining after the destructive distillation of crude petroleum or residual fractions.

coking--distillation to dryness of a product containing complex hydrocarbons, which break down in structure during distillation, such as tar or crude petroleum. The residue of the process is coke.

compound--chemically speaking, a distinct substance formed by the combination of two or more elements in definite proportions by weight and possessing physical and chemical properties different from those of the combining elements.

conversion--the chemical change of one material into another through chemical processes such as cracking, polymerization, alkylation, hydrogenation and isomerization.

cracking--process carried out in a refinery reactor in which the large molecules in the charge stock are broken up into smaller, lower boiling, stable hydrocarbon molecules, which leave the vessel overhead as unfinished cracked gasoline, kerosines and gas oils. At the same time, certain of the unstable or reactive molecules in the charge stock combine to form tar or coke bottoms. The cracking reaction may be carried out with heat and pressure (thermal cracking) or in the presence of a catalyst (catalytic cracking).

crankcase "blowby"--engine combustion gases that do not leave the cylinder through the exhaust manifold but leak into the crank-case.

crude unit--first processing equipment which crude oil reaches after it enters a refinery. Separates the crude oil into at least four different boiling range fractions. The four boiling ranges would be gasoline, distillate, gas oil and topped crude.

cryogenic fuel--a fuel that must be maintained at extremely low temperatures to remain liquid, i.e., liquefied hydrogen, methane, propane, etc.

cycle stock--unfinished product taken from a stage of a refinery process and recharged to the process at an earlier period in the operation.

cyclone separator--a mechanical device for separation of liquid or solid particles from a gas stream by use of centrifugal force.

deactivators--a chemical added to oils and fuels to suppress a reaction or make another chemical inactive.

deasphalting--process for removing asphalt from petroleum fractions, such as reduced crude. A common deasphalting process introduces liquid propane, in which the nonasphaltic compounds are soluble while the asphalt settles out.

desalting--removing calcium chloride, magnesium chloride and sodium chloride from crude petroleum.

desulfurization--the process for removal of undesirable sulfur or sulfur compounds from petroleum products, usually by chemical or catalytic processes.

detergent--a substance having the properties of washing away undesirable substances through lowering of surface tension; wetting, emulsifying and dispersive action; foam formation. Soaps are natural detergents. In a lubricating oil, the property which prevents the accumulation of deposits in engine parts.

detergent additive--a substance incorporated in lubricating oils which gives them the property of keeping insoluble matter in suspension and preventing its deposition where it would be harmful. Such oils are referred to as detergent oils.

dilution--in motor oils in use, the contamination of oil in the crankcase with some of the less volatile portions of the fuel which have passed unburned into the crankcase.

dimer--a molecule formed by union of two simpler molecules, i.e., isobutane dimer is a combination of two molecules of isobutane.

diolefins--a type of open-chain, hydrogen-deficient hydrocarbons which oxidize easily in air and form gum in petroleum products during storage.

direct digital control (DDC)--a process control system using a computer connected directly to the process controls without using conventional control instruments for maintaining preset variables.

dispersant--an additive used to prevent lubricating oil impurities (usually oxidation products) from adhering to each other and forming sludge.

distillate--that portion of a liquid which is removed as a vapor and condensed during a distillation process. As fuel, distillates are generally within the 400°F to 650°F boiling range and include Nos. 1 and 2 fuel, diesel and kerosine.

distillation--the general process of vaporizing liquids, crude oil, or one of its fractions in a closed vessel, collecting and condensing vapors into liquids.

downtime--time during which a machine, department or factory is inactive during normal operating hours.

effluent--material discharged or emerging from a process or from a specific piece of equipment.

electrostatic precipitator--a device used to separate particulate materials from a vaporous stream. Separation is made by electrically charging the solid particles which are then attracted to an electrode of the opposite charge while the vapors pass through without change. This device is commonly used to remove particulates from catalytic cracking unit flue gases.

emulsification--the phenomenon of fine dispersion of one liquid held in suspension in a second liquid in which it is partly or completely imiscible.

end point--the temperature at which the last portion of oil has been vaporized in ASTM or Engler distillation. Also called final boiling point. That point at which titration or other chemical action is deemed complete.

engine oil--generic term applied to oils used for the bearing lubrication of all types of engines, machines and shafting and for cylinder lubrication other than steam engines. In internal combustion engines synonymous with motor oils, crankcase oils.

ergometrics--the study of human reactions to the physical environment to optimize the interaction between man, machine and the workplace.

extreme pressure lubricants (EP)--lubricants which have the property of imparting to rubbing surfaces the ability to carry appreciably heavier loads than would be possible with ordinary lubricants without excessive wear. This property is usually imparted by additives.

flare--a device for disposing of gases by burning.

flash--the lowest temperature at which vapors from an oil will ignite momentarily on application of a flame.

floating roof--special type of steel tank roof which floats upon the surface of the oil in the tank, thereby eliminating tank breathing and reducing evaporation losses.

flowers and sulfur--the element sulfur in a powder state. Sometimes called sulfur flour, sulfur flowers or brimstone.

flue gas--the products of combustion consisting principally of nitrogen, steam and carbon dioxide with small amounts of other components such as oxygen and carbon monoxide.

flue gas expander--a turbine used to recover energy where combustion gases are discharged under pressure to the atmosphere. The pressure reduction drives the impeller of the turbine.

fractions--refiner's term for the portions of oils containing a number of hydrocarbon compounds but within certain boiling ranges, separated from other portions in fractional distillation. They are distinguished from pure compounds which have specified boiling temperatures, not a range.

freeze point--the temperature at which a liquid changes to a solid.

fuel oils--any liquid or liquefiable petroleum product burned for the generation of heat in a furnace or firebox or for the generation of power in an engine. Typical fuels include clean distillate fuel for home heating and higher viscosity residual fuels for industrial furnaces.

gas oil--a petroleum product produced either from the distillation of crude oil or synthetically by a cracking process. The boiling range may vary from 500°F to 1,100°F.

gear oils--lubricating oils for use in standard transmissions, most types of differential gears, and gears contained in gear cases.

grease, lubricating--a solid to semifluid product of the dispersion of a thickening agent in a fluid lubricant. Other ingredients may be added to impart special properties.

heat sink--a mass used to absorb heat. In jet aircraft the fuel may be used for this purpose.

heating oils--trade term for the group of distillate fuel oils used in heating homes and buildings as distinguished from residual fuel oils used in heating and power installations. Both are burner fuel oils.

heavy ends--the highest boiling portion of a gasoline or other petroleum oil.

hydraulic fluid--liquid of petroleum or nonpetroleum origin used in hydraulic systems. Low viscosity, low rate of change of viscosity with temperature, and low pour point are required characteristics.

hydrocarbon--any of a large class of organic compounds containing only carbon and hydrogen, comprising paraffins, olefins, acetylenes, alicyclics and aromatic hydrocarbons. Crude oil, natural gas, coal and bitumens are primarily hydrocarbons.

hydrocracking--the cracking of a distillate or gas oil in the presence of catalyst and hydrogen to form high octane gasoline blending stocks.

hydrodesulfurization--the removal of sulfur from hydrocarbons by reaction with hydrogen in the presence of a catalyst.

hydrofluoric acid--a colorless liquid boiling at 67°F soluble in all proportions in water. The water mixture is extremely corrosive to metals. Adequate safety precautions must be used when working with either liquid or vapor hydrofluoric acid. The use in the oil industry is as a catalyst in alkylation units and in acidizing oil wells.

hydrogen sulfide--a poisonous, colorless, flammable gas, which may be prepared by the direct combination of hydrogen and sulfur. Hydrogen sulfide can be reacted with caustic to form sodium sulfide or charged to a sulfur plant to produce sulfur. A compontent of sour crude oils.

hydrogenation--a refinery process in which hydrogen is added to the molecules of unsaturated (hydrogen-deficient) hydrocarbon fractions. It plays an important part in the manufacture of high octane blending stocks for aviation gasoline and in the quality improvement of various petroleum products.

hydrotreating--a treating process for the removal of sulfur or nitrogen from feedstocks by replacement with hydrogen.

hypoid gears--automotive differential gear system designed to lower the height of the passenger car by having the driveshaft pinion gear meet the axle gear at a point below the centerline. To mesh at this point, the gears must have teeth in a shape which resembles a hyperboloidal curve. This causes the teeth to slide together with high friction as they mesh which makes lubrication of this type gear very critical.

inhibitor--an additive substance which, when present in a petroleum product, prevents or retards undesirable changes taking place in the product, particularly oxidation and corrosion.

in-line blending--see blending.

intermediate crude oil--a crude oil containing both naphthenes and paraffins. Usually of intermediate sulfur content and in the medium gravity range.

isobutane--a hydrocarbon containing 4 carbon atoms and 10 hydrogen atoms, the same as normal butane. Different arrangements of the molecular structure result in different physical properties. Isobutane with olefin(s) is the feed to an alkylation unit to produce high octane gasoline.

isomerization--a refining process which alters the fundamental arrangement of atoms in the molecule. Used to convert normal butane into isobutane, an alkylation process feedstock, and normal pentane and hexane into isopentane and isohexane, high octane gasoline components.

isomers--in petroleum, different compounds composed of the same amounts of carbon and hydrogen but differing in physical properties owing to variation in molecular structure.

isooctane--a hydrocarbon composed of 8 carbon atoms and 18 hydrogen atoms, a liquid at normal temperatures and a highly desirable component of gasoline. Although found in crude oil, the principal source is from synthetic processes such as alkylation.

kinematic viscosity--the absolute viscosity of a liquid (in centipoises) divided by its specific gravity at the temperature at which the viscosity is measured. See viscosity.

knock--the sound or "ping" associated with the autoignition in the combustion chamber of an automobile engine of a portion of the fuel-air mixture ahead of the advancing flame front.

lead--industry parlance for the motor fuel antiknock additive compound tetraethyl lead.

lead susceptibility--the increase in octane number of gasoline imparted by the addition of a specified amount of tetraethyl lead.

linear programming--instructing a computer in mathematical language to perform some action under certain conditions which is aimed at optimizing the objective function.

liquefied natural gas (LNG)--natural gas which has been liquefied at a temperature of minus 258°F for ease of storage and transportation.

liquefied petroleum gas (LPG)--as a rule, it is a mixutre of natural and/or refinery gases, compressed until a liquid and contained under pressure in steel cylinders. It is used as fuel for many different purposes, such as tractors, buses, trucks and stationary engines; for domestic and industrial purposes; and for power generation where commercial natural gas is not available. New uses are constantly being found. A recent development is the use of LPG as a direct quick freezing agent in the frozen foods industry. It is also known and marketed as butane, propane, bottled gas, etc.

lithium-base grease--a lubricating grease prepared from lubricating oil and a lithium soap.

low-sulfur crude oil--crude oil containing low concentrations of sulfur-bearing compounds. Crude is usually considered to be in the low-sulfur category if it contains less than 0.5 weight-percent sulfur. Examples of low-sulfur crudes are offshore Louisiana, Libyan and Nigerian crudes. See also sweet crude.

lube stocks--refinery term for fractions of crude petroleum of suitable boiling range and viscosity to yield lubricating oils when further processed and treated.

mechanical seal--usually applied to the application of sealing a rotating shaft that extends into a vessel containing gas or liquid against escape to the atmosphere as in pumping with a centrifugal pump or mixing material in a vessel using a type of impeller. The seal is effected by having a stationary ring in the seal housing and a rotary ring affixed to the shaft. A spring arrangement keeps the two seal faces together.

mercaptans--organic compounds possessing a thiol group (—SH). The simpler mercaptans have a strong, repulsive, garlic-like odor which becomes less pronounced with increasing molecular weight. Small amounts are intentionally added to LPG so that even small leaks will be readily noticeable.

metal deactivators--organic compounds sometimes added to gasoline to suppress or overcome the tendency of metal compounds in the gasoline to form gum. The metal compounds result from copper-treating the gasoline or from other catalytic metals.

methyl ethyl ketone (MEK)--colorless liquid obtained from petroleum derivatives. A component of a solvent used in dewaxing lubricating oils, also as a chemical intermediate.

molybdenum--silvery-white, very hard, metallic element with physical properties similar to those of iron and chemical properties similar to those of a nonmetal. The oxide of molybdenum with the oxide of cobalt is used to make hydrodesulfurization catalyst.

naphtha--liquid hydrocarbon fractions, generally boiling within the gasoline range, recovered by the distillation of crude petroleum. Used as solvents, dry cleaning agents and charge stocks to reforming units to make high octane gasoline.

naphthenic crude oil--a crude oil that contains a large amount of naphthenic type compounds. A source of naphthenic lubricating oils. Characteristics vary widely between the different producing fields.

natural gas liquids (NGL)--a mixture of liquid hydrocarbons naturally occurring in suspension in natural gas and extracted by various means to yield a liquid product suitable for refinery and petrochemical feedstocks.

nitrogen oxide--any of several oxides of nitrogen, some of which are formed in a mixture as toxic fumes by the action of nitric acid on oxidizable material or by the decomposition of metal nitrates used as catalysts in refineries and the combustion of gasoline in internal combustion engines.

octane number--a term numerically indicating the relative antiknock value of a gasoline. It is based upon a comparison with the reference fuels isooctane (100 octane number) and normal heptane (0 octane number). The octane number of an unknown fuel is the volume percent of isooctane with normal heptane which matches the unknown fuel in knocking tendencies under a specified set of conditions.

olefins--a class of unsaturated (hydrogen deficient) open-chain hydrocarbons of which butene, ethylene and propylene are examples. Propylenes and butylene olefins with isobutane are used in alkylation unit to produce high octane gasoline. Ethylene is the feedstock used by chemical plants to produce polyethylene plastic.

paraffin--a white, tasteless, odorless waxy substance obtained from some petroleum oils.

paraffinic type crude oil--a crude oil containing predominantly paraffinic hydrocarbons. Some types of this crude oil are used to produce high quality motor oils.

petrochemical feedstock--a fraction of crude oil or hydrocarbons which are used as a charge to process units in the production of petroleum based chemicals.

platinum--a silvery-white metallic element closely related to silver and gold. Used in the manufacture of catalysts used in catalytic reforming and isomerization units.

polymer--a product of the polymerization of normally gaseous olefin hydrocarbons to form high octane hydrocarbons in the gasoline boiling range.

polymerization--the process of combining two or more simple molecules of the same type, called monomers, to form a single molecule having the same elements in the same proportion as in the original molecule but having different molecular weights. The product of the combination is a polymer. The combination of two or more dissimilar molecules is known as copolymerization. The product of this combination is a copolymer.

pour depressant, pour point depressant--an additive which lowers the pour point of a lubricating oil. Also pour point inhibitor. Also used in furnace oils to improve low temperature flow and pumpability properties.

pour point--the lowest temperature at which an oil will pour or flow when chilled, without disturbance.

presulfide--a step in the catalyst regeneration procedure which treats the catalyst with a sulfur-bearing material such as hydrogen sulfide or carbon bisulfide to convert the metallic constituents of the catalyst to the sulfide form in order to enhance its catalytic activity and stability.

process unit--a separate facility within a refinery, consisting of many types of equipment such as heaters, fractionating columns, heat exchangers, vessels and pumps, designed to accomplish a particular function within the refinery complex. For example, the crude processing unit is designed to separate the crude into several fractions, while the catalytic reforming unit is designed to convert a specific crude fraction into a usable gasoline blending stock.

propane--a saturated hydrocarbon containing 3 carbon atoms and 8 hydrogen atoms, gaseous at normal temperature and pressure, but generally stored and transported as a liquid under pressure. Used for domestic heating and cooking and for certain industrial purposes, such as metal cutting.

raffinate--in solvent refining, that portion of the oil which remains undissolved and is not removed by the selective solvent.

reference fuel--a standard fuel used in testing performance quality of fuel products.

refinery pool--an expression for the mixture obtained if all blending stocks for a given type of product were blended together in production ratio. Usually used in reference to motor gasoline octane rating.

refluxing--in fractional distillation, the return of part of the condensed vapor to the fractionating column to assist in making a more complete separation of the desired fractions. The material returned is reflux.

reformate--the high octane product from reforming a naphtha.

reforming--the mild thermal cracking of naphthas to obtain more volatile products, such as olefins, of higher octane values or catalytic conversion of naphtha components to produce higher octane aromatic compounds.

Reid vapor pressure (RVP)--the method of measuring vapor pressure. See vapor pressure.

research octane number (RON)--an expression for the antiknock rating of a motor gasoline. Accepted as the guide to the antiknock qualities of fuels when vehicles are operated under conditions associated with low engine speeds.

residual desulfurization (RDS)--the removal of sulfur-bearing compounds from topped crude or viscous residuums obtained in refinery operations.

residual fuel oils--topped crude petroleum or viscous residuums obtained in refinery operations. Commercial grades of burner fuel oils Nos. 5 and 6 are residual oils and include Bunker fuels.

riser cracking--applied to fluid catalytic cracking units where the mixture of feed oil and hot catalyst is continuously fed into one end of a pipe (riser) and discharges at the other end where catalyst separation is accomplished after the discharge from the pipe. There is no dense phase bed through which the oil must pass as all the cracking occurs in the inlet pipe (riser).

road octane--a numerical value based upon the relative antiknock performance in an automobile of a test gasoline as compared with specified reference fuels. Road octanes are determined by operating a car over a stretch of level road or on a chassis dynamometer under conditions simulating those encountered on the highway.

SAE numbers--a classification of motor, transmission and differential lubricants to indicate viscosities, standardized by the Society of Automotive Engineers. They do not connote quality of the lubricant.

scale wax--the paraffin derived by sweating the greater part of the oil from slack wax. It contains up to 6 percent of oil. Also called crude scale.

shear--rate of shear is the ratio of flow rate or velocity (of a lubricant) to the clearance between two parallel surfaces moving in opposite directions. For practical purposes, shearing stress may be considered as the pressure to cause flow and rate of shear as the rate of flow.

silica--dioxide of silicon. Used in the manufacture of glass and refractory materials.

slack wax--soft crude wax obtained from pressing paraffin distillate or wax oil.

smoke point--the maximum height a flame can be extended without smoking the lamp chimney when testing kerosine under specified test conditions.

solid state electronics--low voltage electrical circuiting using transistor-type components. Very rugged and durable with no vacuum tubes or parts susceptible to vibration.

solvent--a substance, usually a liquid, capable of absorbing another liquid, gas or solid to form a homogeneous mixture.

solvent extraction--the process of mixing a petroleum stock with a selected solvent, which preferentially dissolves undesired constituents, separating the resulting two layers and recovering the solvent from the raffinate (the purified fraction) and from the extract by distillation.

sour crude--crude oil which (1) is corrosive when heated, (2) evolves significant amounts of hydrogen sulfide on distillation, or (3) produces light fractions which require sweetening. Sour crudes usually, but not necessarily, have high sulfur content. Examples are most West Texas and Middle East crudes.

stability--in petroleum products, the resistance to chemical change. Gum stability in gasoline means resistance to gum formation while in storage. Oxidation stability in lubricating oils and other products means resistance to oxidation to form sludge or gum in use.

stationary turbine fuel--fuel for industrial turbines as opposed to aircraft-type turbine engines.

stocks--petroleum in storage, both crude and refined products; includes crude awaiting processing and products awaiting transfer to the point of utilization.

straight-run distillate--fraction of crude oil which boils between 400°F and 650°F. Primarily sold as kerosine, heating oil (No. 1 and No. 2 fuel oil), and diesel fuel.

straight-run gasoline--low boiling fraction of crude oil which, after further processing, is used as a finished motor gasoline blending stock.

substitute natural gas (SNG)--a gas having similar chemical and use properties to natural gas. Manufacturable from petroleum liquids, coal and other hydrocarbons.

sulfonates--a group of petroleum hydrocarbons resulting from treating oils with sulfuric acid. Used as synthetic detergents, emulsifying and wetting agents, and chemical intermediates.

sulfuric acid--a heavy corrosive oily dibasic strong acid that is colorless when pure and is a vigorous oxidizing and dehydrating agent. Composed of sulfur, oxygen and hydrogen. Used in the chemical refining of petroleum products. One of the two commonly used catalysts for alkylation units.

surfactant--a substance which imparts emulsifiability, spreading, wetting, dispersibility or other surface-modifying properties.

sweet crude--crude oil which (1) is not corrosive when heated, (2) does not evolve significant amounts of hydrogen sulfide on distillation, and (3) produces light fractions which do not require sweetening. Sweet crude always has low sulfur content. Examples are offshore Louisiana, Libyan and Nigerian crudes.

sweetening--the process of improving petroleum products in color and odor by converting the undesirable sulfur compounds into less objectionable disulfides or by removing them by contacting the petroleum stream with alkalies or other sweetening agents.

synthetic detergents--liquid or solid materials capable of dissolving oily materials and dispersing or emulsifying them in water. Petroleum sulfonates are examples of synthetic detergents.

synthetic lubricants--a group of products, some of which are made from petroleum hydrocarbons, natural gas or refinery gases, which are used as oils or lubricating greases where heat, chemical resistance and other requirements can be better met than with straight petroleum products.

tetraethyl lead (TEL)[$Pb(C_2H_5)_4$]--a volatile lead compound which is added in concentrations up to 3 cc. per gallon to motor and aviation gasoline to increase the antiknock properties of the fuel.

tetramethyl lead (TML)[$Pb(CH_3)_4$]--a highly volatile lead compound added to motor gasoline to reduce knock. May be used alone or in mixtures with TEL.

thermal cracking--a refining process which decomposes, rearranges or combines hydrocarbon molecules by the application of heat without the aid of catalysts.

thiophosphates--lube oil additives formed by the combination of sulfur and phosphorus. Usually P_2S_5, phosphorus pentasulfide, sometimes called phosphoric sulfide, phosphorus persulfide or thiophosphoric anhydride. These additives are usually supplemented by more conventional additives, i.e. barium salts.

toluene--an aromatic solvent having a specific gravity ranging between 0.8690 and 0.8730. Has many chemical uses and may be a component of aviation gasoline or motor gasoline.

topped (reduced) crude--a residual product remaining after the removal, by distillation or other processing means, of an appreciable quantity of the more volatile components of crude petroleum.

topping--the distillation of crude petroleum to remove the light fractions only.

total oxygen demand (TOD)--for aqueous effluents, the sum of chemical and biological oxygen demand.

trace contaminants--impurities present in small concentrations.

tricresyl phosphate (TCP) [$PO(OC_6H_4CH_3)_3$]--colorless to yellow liquid used as a gasoline and lubricant additive and plasticizer.

trimer--a molecule formed by union of three simpler molecules of the same compound.

unsaturates--hydrocarbon compounds of such molecular structure that they readily pick up additional hydrogen atoms. Olefins and diolefins, which occur in cracking, are of this type.

vacuum distillation--distillation under reduced pressure, which reduces the boiling temperature of the material being distilled sufficiently to prevent decomposition or cracking.

vacuum unit--a unit operated below atmospheric pressure which allows vaporization of more of the heavier gas oil molecules from the crude residue without thermal disintegration of the molecules.

vapor lock--the displacement of liquid fuel in the feed line and the interruption of normal motor operation, caused by the vaporization of light ends in the gasoline. Vaporization occurs when the temperature at some point in the fuel system exceeds the boiling points of the volatile light ends.

vapor pressure--the pressure exerted by the vapors released from an oil at a given temperature when enclosed in an airtight container. For motor gasoline a criterion of vapor-lock tendencies; for light products generally an index of storage and handling requirements.

vapor recovery system--system for controlling hydrocarbon vapor losses from a refinery.

virgin gas oil (VGO) desulfurization--the removal of sulfur-bearing compounds from hydrocarbon fractions boiling in the gas oil range and containing no cracked material.

virgin stock--oil processed from crude oil which contains no cracked material. Also called straight-run stock.

visbreaking--lowering or breaking the viscosity of residuum by cracking at relatively low temperatures.

viscosity--the measure of the internal friction or resistance of an oil to flow.

viscosity index--a scale showing the magnitude of viscosity changes in lubricating oils with changes in temperature.

volatility--that property of a liquid which denotes its tendency to vaporize.

water scrubber--a mechanical device usually applied to a gas containing particulate matter in which water is sprayed countercurrent into the stream. The water containing solids is usually sent to some means of separating the solids from the water.

wax--a term used loosely for any of a group of substances resembling beeswax in appearance and character and, in general, distingished by their composition of esters of the higher alcohols and by their freedom from fatty acids.

yield--in petroleum refining, the percentage of product or intermediate fractions based on the amount charged to the processing operation.

zeolitic catalyst (fluid catalytic cracking)--catalyst is normally considered to be of two types: natural clays can be used or a synthetic clay can be chemically produced. Since the early 1960's, modern cracking catalysts contain a silica-alumina crystalline structured material called zeolite. This zeolite is commonly called a molecular sieve. The admixture of a molecular sieve in with the base clay matrix imparts desirable cracking selectivities.